CITY OF CHULA VISTA
MUNICIPAL ENERGY UTILITY
FEASIBILITY ANALYSIS

APPENDICES

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APPENDIX A

ABBREVIATIONS, ACRONYMS, GLOSSARY OF TERMS

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ENTITIES

APX	Automated Power Exchange
CAISO	California Independent System Operator Corporation
Calpine	Calpine Energy Services, LP
CEC	California Energy Commission
CPUC	Public Utilities Commission of the State of California
CRE	Comision Reguladora De Energia (Mexico's Energy Regulatory Commission)
DWR	California Department of Water Resources
Duke	Duke Energy North America
EPA	Environmental Protection Agency
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
LADWP	Los Angeles Department of Water and Power
PG&E	Pacific Gas and Electric Company
PG&E NEG	PG&E National Energy Group
PX	California Power Exchange
SANDAC	San Diego Regional Planning Agency
SDAPCD	San Diego Air Pollution Control District
SMUD	Sacramento Municipal Utility District

SDG&E	San Diego Gas & Electric Company
SCE	Southern California Edison Company
SoCal Gas	Southern California Gas Company
WECC	Western Electricity Coordinating Council

TERMS

APD	Abnormal Peak Day
Bcf	One Billion Cubic Feet of gas
Btu	British Thermal Unit
CAT	Core Aggregation Transportation
CCA	Community Choice Aggregation
CCGT	Combined Cycle Gas Turbine
CEQA	California Environmental Quality Act
CGR	California Gas Report
CPCN	Certificate of Convenience and Public Necessity
CRR	Congestion Revenue Rights
CRS	Cost Responsibility Surcharge
CSA	Comprehensive Gas OII Settlement Agreement
CTS	Competitive Transition Charge
DA	Direct Access
DG	Distributed Generation

DRP	Demand Response Program
EG	Electric Generation
ERC	Emission Reduction Credits
ESP	Energy Service Provider
FSD	Firm Demand Service
FPA	Federal Power Act
GMC	Grid Management Charge
GW	Gigawatt (1 million kilowatts)
GWh	Gigawatt Hour
HHD	Households
IOU	Investor Owned Utility
JPA	Joint Powers Agency
KW	Kilowatt (one thousand watts)
kWh	Kilowatt Hour
LAFCO	Local Agency Formation Commission
LDC	Local Distribution Company
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
LOLP	Loss Of Load Probability
Mbtu	One Thousand Btus

MCf	One Thousand Cubic Feet of Gas
MDL	Municipal Departing Load
MEU	Municipal Electric Utility
MDU	Municipal Distribution Utility
MMBtu	One Million Btus
MMcf	One Million Cubic Feet of Gas
MPPSA	Master Power Purchase and Sale Agreement between Calpine and DWR dated May 1, 2002
MW	Megawatt
NBP	Mexican North Baja Pipeline
NPV	Net Present Value
O&M	Operations And Maintenance
OFO	Operational Flow Order
PTO	Participating Transmission Owner
QF	Qualifying Facility
PUD	Public Utility District
RCN	Replacement Cost New
RCNLD	Replacement Cost New Less Depreciation
RPS	Renewable Portfolio Standard
SIL	Simultaneous Import Capability Limitation
SMD	Standard Market Design

TCF	One Trillion Cubic Feet of Gas
TGN	Transportado de Gas Natural de Baja California (Rosarito Pipeline)
URG	Utility Retained Generation
VOC	Volatile Organic Compounds
WDAT	Wholesale Distribution Access Tariff

GLOSSARY OF TERMS

Base Load	The minimum constant level of electric demand, expressed in units of watts, that a utility's generating system must meet.
Base Load Unit	An electric generating plant, or generating unit within a plant, that is normally operated continuously to meet the system's base load, or minimum constant level of electric demand.
Capacity	A measure of the amount of service for which a system or system component is rated.
Capacity Factor	A measure of the degree to which the capacity of a generating unit or utility is being used during a certain period of time.
City gate	The site where a distribution utility company receives and measures gas from a pipeline company.
Coincident (Peak) Demand	The level of demand of an electric or natural gas customer or customer class at the time of the electric or gas system's peak demand.
Cost-of-Service	The total costs incurred by a utility in providing utility service.
Customer Classes	Groups of utility customers with similar characteristics that are classified together for the setting and applying of electric and natural gas rates and for other ratemaking and financial reporting purposes.
Degree Day	A unit of measure used to express the extent to which temperatures vary from a specific reference temperature during a given time period.

Demand	The amount of energy drawn by customers at a specific time.
Direct Access	The ability of a retail customer to purchase electricity directly from the wholesale market rather than through a local distribution utility.
Distributed Generation	Small scale generation located at or near the point of end use.
Distribution	The delivery of electricity to the retail customer's home or business through low voltage distribution lines.
Energy	A measure of the quantity of units of electricity used in a give time period, measured in kilowatt-hours.
Heat Rate	A measure of the amount of thermal energy needed to generate a given amount of electric energy.
Load	The amount of power carried by a utility system, or the amount of power consumed by an electric device, at a specified time.
Load Factor	A ratio that indicates the amount of variability in electric demand for a specific period of time.
Load Profile	An allocation of electricity usage to discrete time intervals over a period of time, based on individual customer data or averages for similar customers. Used to estimate electric supply requirements and determine the cost of service to a customer.
Load Shape	The graphed pattern of a utility's load or customer's demand for energy over a period of time.
Local Distribution Company	A public utility that delivers natural gas to end-use customers through its own distribution system.
Peak Load	The maximum amount of energy carried by a utility system during a specific time period. Peak load determines the required system capacity.
Peaking Unit	An electric generating plant, or generating unit within a plant, operated to meet maximum (peak) demand or to fill emergency requirements.

Rate Design	The process of setting prices for utility service at levels that permit a utility to collect the total revenues allowed by regulators in a manner that meets current regulatory and legislative policy goals.
Rate of Return	The amount earned, or allowed to be earned, by a utility, expressed as a percentage of the utility's rate base.
Rate Structure	The combination of the rate components and rate designs a utility uses to bill its various classes of customers for the electric, natural gas, or other utility service provided to them.
Revenue Requirement	The total amount of money a utility must collect from its customers to pay all operating and capital costs, including a fair return on investment.
Substation	An assemblage of equipment that switches, changes, or regulates voltage in the electric transmission and distribution system.
Transformer	A device that changes the voltage of alternating current electricity.

APPENDIX B

REGULATORY AND LEGISLATIVE ISSUES

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I. REGULATORY AND LEGISLATIVE ISSUES

The purpose of this section of the Report is to describe the current legal, regulatory, political and economic framework under which an MEU would operate, the challenges and opportunities presented thereby, and opportunities to overcome or take advantage of such challenges and opportunities.

A. Historical Perspective

Since the passage of the Energy Policy Act amendments to the Federal Power Act in 1992[1] and the adoption of FERC Order Nos. 888[2] and 889[3] in 1996 and 1997 respectively, the FERC has attempted to develop the foundation necessary to develop competitive bulk power markets in the United States. The foundation consisted of implementing non-discriminatory open access transmission services by public utilities and stranded cost recovery rules that would provide a fair transition to competitive markets.

With these changes in Federal laws and regulatory policy, various States have responded with various types of reform, some including major utility reforms, deregulation and the development of Independent System Operators to consolidate the operation of state and regional transmission grids.

Efforts to restructure the California electric industry began in 1994 in response to high electric rates.[4] Following extended hearings, negotiations and proceedings before the CPUC which resulted in a restructuring Order issued in December 1995,[5] the California Legislature enacted Assembly Bill 1890 (AB 1890) in September, 1996. The principle factors of AB 1890

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1 Energy Policy Act, 42 U.S.C. § 13201 et seq. (2002).

2 See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996)(Order No. 888), order on reh'g, Order No. 888-A, 62 FR 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997)(Order No. 888-A), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in part sub nom. Transmission Access Policy Study Group V. FERC, 224 F.2d 667 (D.C. Cir. 2000), cert granted sub nom., New York v. FERC, 531 U.S. 1189 (2001)

3 Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct, Order No. 889, 61 FR 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), order on reh'g, Order No. 889-A, 62 FR 12,484 (March 14, 1997), FERC Stats. & Regs. ¶ 31,049 (1997), order on reh'g, Order No 889-B, 81 FERC ¶ 61,253 (1997).

4 At the time, California's electric rates were almost twice the national average at 10 to 11 cents per kilowatt hour.

5 See CPUC Decision D. 95-12-063 (December 20, 1995), modified by D. 96-01-009 (January 10, 1996) and D. 96-03-022, 166 PUR 4th 1.

included (1) creation of the California Independent System Operator Corporation (CAISO) and the California Power Exchange (PX) and simultaneous initiation of direct access; (2) creation of the California Electricity Oversight Board; (3) a competitive transition charge (CTC) for the recovery of the Investor-Owned Utility's (IOU) stranded costs; and (4) a 10% rate reduction for residential and small customers and a rate freeze for all retail customers. Among other things, AB 1890 mandated that the investor-owned utilities in the State: (1) turn over the operational control of their transmission facilities to the CAISO; (2) divest at least half of their fossil fuel fired generating plants; and (3) buy and sell through the PX.

In March 1997, the CAISO and PX submitted filings with the FERC to implement the requirements of AB 1890 and, after significant revisions of the CAISO and PX Tariffs as required by the FERC's July 30, 1997 Order, the ISO and PX were permitted to commence operations on March 31, 1998, pursuant to the Commission's Order dated October 30, 1997.[6]

Immediately following the commencement of operations by the ISO and PX, prices for power and ancillary service began to spike. The ISO sought and obtained the imposition of price caps as a solution to the volatility and thinness in the market for ancillary services. The FERC authorized price caps, but required the ISO to eliminate the price caps by November 15, 1999. In September 1999, the ISO filed proposed tariff revisions to extend and increase its price caps. The FERC approved the proposal and permitted the price caps to remain in effect through November 15, 2000.

The electricity market in California remained both chaotic and volatile despite numerous amendments to the ISO and PX Tariffs and other attempts by the ISO and PX to stabilize the market. These efforts notwithstanding, electricity prices in California jumped dramatically in the summer of 2000 and affected all markets run by the PX and the ISO. High temperatures and generation outages led the ISO to declare numerous (39) system emergencies. These efforts did not prevent rolling blackouts in Northern California or the continuation of increases in both electric and gas prices.[7]

During the summer of 2000, the cost of electricity imports began to increase, particularly gas costs which resulted in unprecedented increases in the cost of operating existing gas fired units.

Because the retail rate freeze imposed in SDG&E's service area by AB 1890 ended in 1999, the very high wholesale prices were passed through to the utility's retail

6 Pacific Gas and Electric Co. et al, 81 FERC ¶ 61,122 (1997).

7 Based on subsequent disclosures in numerous ongoing proceedings before the FERC, certain generators and suppliers of electricity, gas and ancillary services "gamed" the ISO and PX markets which exacerbated the problems already faced by participants in the California electricity markets. Efforts are currently under way to recover some of the profits which were received by those that "gamed" the California energy markets in 2000 and 2001.

customers, resulting in electric bills that were up to 200-300 percent higher than in the previous year.

While the price freeze applicable to customers of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) remained in effect until March 31, 2002, both utilities were required to absorb enormous shortfalls that could not be recovered in retail rates. As a result, PG&E was driven into bankruptcy and is still seeking approval of a plan to emerge from bankruptcy. SCE was driven to the edge of bankruptcy, but instead entered into a settlement with the CPUC that kept the company from filing for bankruptcy. That settlement is still the topic of appeal in the State's Supreme Court.

While electricity and gas markets have stabilized somewhat since the 2000-2001 period, no long-term solution to high electricity and gas prices has emerged. The CAISO has now filed some fifty-nine (59) amendments to the CAISO Tariff seeking reforms which would further stabilize the markets served by the CAISO. The PX, after two years of disappointing results, was also driven to bankruptcy and was dismantled in 2002 after the requirement that the IOUs purchase and sell power through the PX was terminated by the FERC.

It is relevant to point out that, while all electric and gas customers in California have suffered dramatic increases in electric rates since the implementation of AB 1890, the customers of publicly owned electric systems have suffered less and some have barely felt the volatility of the market. The fact that publicly owned utilities have fared much better during restructuring than the IOUs is attributable to the following factors:

(1) Publicly owned utilities were allowed, but not required by AB 1890 to participate in either the CAISO or the PX markets;

(2) Publicly owned electric utilities were encouraged by the California Legislature, but not required by the terms of AB 1890, to turn the operational control of their transmission facilities and rights over to the CAISO;

(3) AB 1890 did not mandate, and the FERC did not order the abrogation of the existing contracts and service arrangements held by publicly owned electric utilities which entitled them to long-term, reliable and relatively low-cost power and energy. To the contrary, the FERC orders issued in the restructuring proceedings have consistently preserved the integrity of existing contracts of publicly owned utilities, regardless of their term; and

(4) AB 1890 and related FERC orders have not required publicly owned utilities owning transmission assets to become Participating Transmission

Owners (PTOs) under the CAISO Tariff, although they have the right to become a PTO at their option.

It is clearly the goal of the California Legislature and the FERC to eventually require all utilities, both public and private, to participate in all markets on equal terms. Thus far the CAISO has failed to demonstrate that participation in the CAISO markets would result in any economic benefit to publicly owned electric utilities or their customers. Until that happens, publicly owned electric utilities will continue to avoid, where possible, the imposition of costs or obligations resulting from full participation in the CAISO markets.

It is in this context that Chula Vista must weigh the alternatives for developing and implementing a Chula Vista MEU. By all standards, the California restructuring experiment under AB 1890 has been a miserable failure. Efforts to find viable long-term solutions which will stabilize markets and bring both electric and gas costs down to reasonable levels are continuing, but the market remains broken. The CAISO just filed Amendment No. 59 to the CAISO Tariff and is mired in litigation over past amendments and practices. Each of the investor-owned utilities is seeking increases in various rates for scheduling coordinator services, ancillary services, interconnection charges and other services provided to their wholesale customers or to the CAISO. The IOUs have also filed a number of cases to determine the extent to which they can pass on to their customers the charges imposed on them by the CAISO. On top of this, almost all participants in the California energy market are involved, directly or indirectly, in a spate of refund cases in which the California Attorney General and other California parties claim overcharges for electric service provided in 2000 and 2001.

Undoubtedly, the foregoing factors are the very root causes for Chula Vista to examine its alternatives to continuing its dependency on SDG&E for full requirements electric and gas service. At the same time, however, these factors must be carefully considered by Chula Vista in the context of its feasibility analysis to the end that it can free the City of its dependency on the current paradigm for providing utility services and, at the same time, avoid the pitfalls which may occur if Chula Vista becomes an active participant in the California energy markets.

B. San Diego Region

The impacts of California's 1996 restructuring legislation (AB 1890) were particularly devastating to customers of SDG&E. Pursuant to AB 1890, retail electric rates were "frozen" at levels above SDG&E's actual costs until March 31, 2002, or such earlier time as SDG&E had recovered its uneconomic, or "stranded" costs of generation assets. Ironically, due to SDG&E's relatively low stranded costs, the rate freeze originally designed to protect customers ended during the early months of the electricity crisis, leaving customers exposed to the volatility of the market, resulting in retail rates rising to unprecedented levels.

In response to this localized rate crisis, the California Legislature enacted emergency legislation to address the "severe economic hardship" to SDG&E ratepayers "because of unprecedented bill volatility and extraordinarily high rate levels." AB 265 (Stats. 2000, Ch. 328; Cal. Pub. Util. Code § 332.1) required the CPUC to establish, retroactive to June 1, 2000 a rate ceiling of $.065 on the energy component of electric bills for residential, small commercial, and street lighting customers[8] of SDG&E. The rate ceiling was to remain in effect until December 31, 2002. The legislation also required an accounting procedure to track and recover the undercollections caused by the rate ceiling.

In subsequent applications filed with the CPUC, SDG&E sought approval of a surcharge to recover the undercollections. Due to a settlement of litigation with the CPUC and other factors which were expected to eliminate the undercollection by the end of 2003, the Commission denied the request for a surcharge in Decision 02-12-064.

C. Legal and Regulatory Framework

For the most part, MEUs are self-regulated under both the laws of the State of California and Federal laws. Neither the CPUC nor the FERC have general rate and service jurisdiction over the activities, transactions and rates of publicly-owned and operated utilities.

That said, the restructuring of the California electric industry and changes in Federal laws and regulations have resulted in the extension of some regulatory authority, at both the State and Federal level, over certain aspects of the operation of MEUs. In deciding whether to form and operate a MEU, and in selecting the type of legal structure to be used to accomplish this objective, it is important for cognizant officials of Chula Vista to understand the legal and regulatory framework with respect to MEU formation and operation.

1. California Regulatory Framework

a. Legislation

Prior to the enactment of AB 1890 in 1996, the California Legislature rarely found it necessary to dictate how municipally owned utilities or other non-investor owned utilities operated. The investor owned utilities, with their exclusive service territories, were closely regulated by the CPUC, and the publicly owned utilities, having no intent to expand their service territories beyond their own borders, were regulated by their own elected boards, councils, and commissions. The drive to introduce competition into the electric industry altered the regulatory landscape in significant ways. Non-utility generators, marketers, and brokers were permitted to sell power at retail, utilizing the existing distribution systems of the existing

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[8] The CPUC was also required to establish a voluntary program for large commercial, agricultural, and industrial customers who bought energy from SDG&E to pay at the same $.065 rate with a true-up after a year.

utilities. New entities were created to establish a trading market for electricity and to control essential transmission facilities under FERC jurisdiction. The California Legislature and the CPUC struggled with the notion of local control of publicly owned utility systems.

As part of the California electric industry restructuring, the California Legislature did enact a number of statutory requirements, some mandatory and some discretionary, which now apply to "each local publicly owned electric utility" operating within the State. The term "local publicly owned electric utility" is a term defined in Cal. Pub. Util. Code § 9404 (d) as follows:

> (d) "Local publicly owned electric utility" as used in this division means a municipality or municipal corporation operating as a "public utility" furnishing electric service as provided in Section 10001, a municipal utility district furnishing electric service formed pursuant to Division 6 (commencing with Section 11501), a public utility district furnishing electric services formed pursuant to the Public Utility District Act set forth in Division 7 (commencing with Section 15501), an irrigation district furnishing electric services formed pursuant to the Irrigation District Law set forth in Division 11 (commencing with Section 20500) of the Water Code, or a joint powers authority that includes one or more of these agencies and that owns generation or transmission facilities, or furnishes electric services over its own or its member's electric distribution system.

Thus, the term "local publicly owned electric utility" would apply to any legal structure discussed in this Report and under which Chula Vista could legally form and operate a MEU under California law.

Several statutes applicable to investor owned utilities as well as local publicly owned utilities were contained in the primary restructuring legislation, AB 1890. One such measure mandates surcharges on electricity usage to fund programs considered to be in the public interest. Cal. Pub. Util. Code § 385 requires each local publicly owned electric utility to establish a nonbypassable, usage based charge (commonly referred to as a "public goods" or "public benefits" charge) on local distribution service to fund investment in: (1) cost-effective demand-side management services to promote energy efficiency and energy conservation; (2) new investment in renewable energy resources and technologies; (3) research, development and demonstration programs to advance science or technology; and/or (4) services provided for low-income electricity customers (e.g., energy efficiency services, education, weatherization and rate discounts). The amount of the public benefits charge (on a percent of revenue basis) is the result of a complex formula set out in § 385, but must be "not less than the lowest expenditure level of the three largest electrical corporations in California." Currently, the public benefits charge percentage for local publicly owned utilities is 2.85%. The selection of public benefit programs to be funded by the charge is at the discretion of the local publicly owned utility, but must conform to the statutory requirements of § 385. Other legislation applicable to local publicly owned utilities involves consumer protection programs, and addresses such issues as low-income ratepayer assistance programs, weatherization programs, public reporting of revenues transferred to a city's general fund, and development of renewable resources. Limited only by the categories of "public benefits" set forth in the Code, municipal utilities have complete control over the funds collected, and can use 100% of those funds within the community. Public Goods Funds collected from local ratepayers by the investor owned utilities can be used on any number of programs approved by the utility, and may never be expended within the community in which they are collected.

One of the more controversial discretionary measures involves the extent to which local publicly owned utilities should commit control of their transmission facilities to the CAISO. Cal Pub. Util. Code § 9600 (under which AB 1890 is included) is non-mandatory with respect to the transmission facilities of publicly owned electric utilities, although parallel Code provisions applicable to the State's three investor-owned utilities mandated that those utilities turn over the operational control of their transmission facilities to the CAISO. On March 31, 1998, PG&E, SCE and SDG&E transferred the operational control of their transmission systems to the CAISO. More recently, the Cities of Vernon, Anaheim, Azusa, Banning and Riverside, have become Participating Transmission Owners (PTO) and have transferred the operational control of their transmission facilities and rights to the CAISO.

Section 9600 of the Public Utilities Code also sets forth the guidelines for establishing access charge rates and rates for transmission service, but recognizes that the FERC has jurisdiction to approve transmission rates for investor-owned utilities and the CAISO. FERC has also asserted indirect regulatory authority over the rates charged by publicly owned electric utilities that become PTOs by approving the terms and conditions of the Participating Transmission Owner Agreement between the CAISO and the PTO. Currently, the terms and conditions of the agreements between the CAISO and the publicly owned electric utilities that have become PTOs are still in litigation before the FERC.

AB 1890 made direct access mandatory for the state's investor owned utilities, but optional for local publicly owned utilities. Cal. Pub. Util. Code § 9602 requires that the local regulatory body of each publicly owned electric utility shall, after public hearing, determine whether it will authorize direct transactions between electric suppliers and end use customers. However, if a program of direct access is authorized, Cal. Pub. Util. Code § 9601 requires that any utility or other energy service provider that undertakes to provide partial or full requirements electric service to customers of a local publicly owned electric utility must ensure that such customers pay that utility a nonbypassable generation-related severance fee or transition charge established by the regulatory body for that utility.

The parallel requirement in § 9601 requires any local publicly owned utility that undertakes to provide full or partial requirements electric service to the customers of an investor-owned utility ensure that such customers commit to pay a nonbypassable generation-related transition charge to the investor-owned utility. This provision would apply to the City of Chula Vista if it undertakes, through its MEU, to provide full or partial requirements electric service to the customers of SDG&E through a direct access program.

b. Public Utilities Commission Regulation

As discussed earlier in this Report, case law supports the constitutional and statutory rule that local publicly owned utilities are not subject to the jurisdiction of the CPUC in the absence of a legislative grant of authority. As a rule, the CPUC has respected this limitation. What many municipal utilities considered a departure from this practice occurred in 1998 when, in a controversial decision, the CPUC determined that municipal and other publicly owned utilities were subject to the inspection and maintenance standards for electric distribution systems set out in the CPUC's General Order 165 (Decision 98-03-036; Rehearing Denied in Decision 98-10-059).

Of far greater significance to Chula Vista however, is a proceeding currently ongoing at the CPUC (Rulemaking 02-01-011) in which a decision was issued that would require Chula Vista's MEU customers to pay a surcharge for a variety of costs arising from restructuring and from the California energy crisis (Decision 03-07-028; Limited Rehearing Granted in Decision 03-08-076 (collectively, the MDL Decisions)).

When the legislature enacted Assembly Bill 1 from the First Extraordinary Session (AB 1X) in January 2001, authorizing the California Department of Water Resources (DWR) to begin purchasing electricity for the customers of the state's IOUs, it also directed the CPUC to suspend the state's direct access program, which the Commission did on September 20, 2001. What ensued was a protracted proceeding at the CPUC to determine if direct access customers that left IOU service after February 1, 2001 should be liable for any portion of the cost of power that was ostensibly purchased on their behalf by DWR. An argument was raised that, if these customers were able to avoid liability for at least a portion of the costs incurred by DWR, then those same costs would be shifted to existing bundled service customers. The Commission determined that direct access customers who received any power from one of the three IOUs after February 1, 2001 were liable for a cost responsibility surcharge (CRS or Exit Fees), to cover the cost of (1) DWR's bond charges (which paid for power already purchased); (2) DWR's going forward costs to pay for long term contracts entered into by DWR; (3) a "tail" or residual competition transition charge (Tail CTC); and (4) for customers within the service territory of Southern California Edison, an historical procurement charge to cover SCE's past uncollected procurement costs.

During the course of the proceeding, the issue of Municipal Departing Load (MDL) was raised. Municipal departing load is generally considered to be comprised of electric service customers that were formerly customers of an IOU, but which became customers of a publicly owned utility by way of an annexation of land or by formation of a new municipal utility. Municipal departing load also consists of new customers being served by a publicly owned utility, which were located in the former service territory of an IOU. On March 29, 2002, the assigned administrative law judge issued a ruling noting that separate hearings would be held to determine whether MDL would be liable for any CRS. Testimony was submitted, hearings were held, and the Commission was briefed. On July 10, 2003, the CPUC issued D.03-07-028, *Order Adopting Cost Responsibility Surcharge (CRS) Mechanisms for Municipal Departing Load* (Decision), which imposes the CRS on Municipal Departing Load.

The Decision was adopted by a three to two vote. Commission President Peevey and Commissioner Kennedy both voted against the Decision in light of Senate Concurrent Resolution (SCR) 39, also passed on July 10, 2003 by a unanimous vote (with Senator Bowen abstaining). SCR 39 provides "*that the Legislature intends that any municipal utility serving customers in newly developed areas shall be exempt from any exit fees, as long as the municipal utility was formed before June 1, 2003, and demonstrates that it has expended in good faith significant amounts of money and resources towards creation of a municipal utility that will serve customers in newly developed areas . . . .*" While SCR 39 does not have the force of law and has no binding authority on the Commission, it did show the CPUC that the California Legislature does not support applying the CRS to Greenfield load for new municipal utilities. However, since the Assembly never took up this issue, the import of SCR 39 was largely lost, and the applications for rehearing of D.03-07-028 were, for the most part, denied by the CPUC in Decision 03-08-076, which was issued on August 21, 2003.

<u>Treatment of "Existing Utilities" under the MDL Decisions</u>:

The Decision provides no exemptions for existing MDL (i.e., load that a publicly owned utility acquires from an investor owned utility by virtue of an annexation). Any newly acquired territory that includes facilities already interconnected to the IOU's facilities would be subject to the CRS.

For purpose of applying the CRS, MDL does not include new load of an existing publicly owned utility (those publicly owned utilities established and providing electricity to retail end-use customers on or before February 1, 2001) providing electricity within its exclusive service territory. However, under P.U. Code section 369, "'new load,' for purposes of CRS recovery, excludes load being met through a direct transaction that does not otherwise require the use of transmission and distribution facilities owned by the IOU." New municipal load where the municipal agency is interconnected with and uses the IOU's transmission system, is not exempted.

Treatment of New Publicly Owned Utilities Under the MDL Decisions:

The Decision provides that "*new MDL served by a new publicly-owned utility will be subject to cost responsibility surcharges. The cut-off date will be determined by whether the publicly-owned utility was established and providing electricity to retail end-use customers on or before February 1, 200.*"

The MDL CRS includes *all* of the following elements:

a. DWR Bond Charge, applied on the same per-kWh basis as adopted for bundled customers pursuant to D.02-12-082, which modified D.02-11-074, applicable to MDL customers in the IOU service territory as it existed on February 1, 2001.

b. DWR Power Charge, applicable to MDL customers in the IOU service territory as it existed on February 1, 2001

c. Tail CTC covering the components specified in Cal. Pub. Util. §367, applicable to MDL customers in the IOU service territory as of December 20, 1995.

d. HPC component (for SCE service territory only) applicable to MDL customers that departed the IOU service territory after March 29, 2002.

In D.03-08-076, the CPUC denied the applications for rehearing filed by several parties, and further pared back any possible exemption for the application of the CRS to new Municipal Departing Load. Petitions for Writ of Review were filed with the California Supreme Court in September 2003 by several parties, including Chula Vista. Since that time, respondent CPUC and IOUs have filed their replies, but it is unknown when the Supreme Court will act on the Petitions or if they will be granted.

Accordingly, under the current state of the law, as muddled as it is, Chula Vista will be subject to the cost responsibility surcharges discussed above once it interconnects with SDG&E, begins serving load and begins using the transmission system.

c. California Energy Commission and other State and Federal Environmental Requirements

An MEU which owns and operates electric generation facilities in the State of California may, under certain circumstances, be subject to regulation related to environmental issues by both State and Federal regulatory agencies. In this section, we identify the State and Federal agencies with jurisdiction over environmental issues associated with new or repowered electric generation in the Chula Vista area and the threshold size/emissions that trigger their jurisdiction. This analysis should be refined if and when a decision is made to go forward and more specifics are provided for the project.

- If the Project involves a thermal power plant with over 50 MW net generating capacity or modifications that result in a 50 MW or higher increase in generating capacity, the California Energy Commission (CEC) has exclusive jurisdiction over certifying the site and related facilities. The CEC is directed by statute to consult with other responsible local, regional or state agencies and to make a finding regarding whether the project complies with all applicable laws and ordinances. The most significant of these agencies are identified below. The CEC, however, has the jurisdiction to override the decisions of other local, state or regional agencies if certain conditions are met, namely that the project is needed for public convenience and necessity and there is no more prudent and feasible means of achieving such public convenience and necessity.

  If a plant is below the 50 MW threshold for CEC jurisdiction, the City could undertake a review of the environmental effects of the project consistent with the California Environmental Quality Act (CEQA). However, unlike the CEC, the City does not have exclusive jurisdiction and would have to obtain separate permitting approvals from the other agencies involved, such as the San Diego Air Pollution Control District (SDAPCD).

- The SDAPCD would be the primary agency with responsibility over air emissions from a new plant in the Chula Vista area unless the CEC has jurisdiction. Most significantly, if annual emissions from a new project exceed 50 tons of NOx or VOCs the plant would have to obtain offsets or purchase emission reduction credits (ERCs); both of which are in limited supply in the SDAPCD. In the South Bay Repowering option, the existing (retired) plant may be able to provide offsets. Any ERCs or offsets would need to be approved by the SDAPCD. Because the SDAPCD has recently submitted a request to EPA for redesignation as attainment, these requirements may change in the future.

- EPA Region IX and the California Air Resources Board could also be involved in the review. For example, EPA Region IX has recently revoked the SDAPCD's delegated authority over Prevention of Significant Deterioration (PSD) requirements. To the extent that any new plant, for example, exceeds the 100/250 ton PSD thresholds for carbon monoxide or PM10, EPA could issue this permit. We have also heard informally from the

SDAPCD Staff that EPA, despite the revocation of the SDAPCD's authority, has been willing to informally delegate this authority back to the SDAPCD. Depending on the plant=s location, Federal Land Managers (*e.g.*, National Park Service, Forest Service and/or Fish and Wildlife Service) may be involved regarding the impacts of new generation on Class I areas.

- A new plant could raise water permit issues. For example, stormwater permits could be required for the new construction or if the construction involves cooling towers, permits could be required for them. Depending on the issue, the State Water Resources Control Board, the San Diego Regional Water Quality Control Board and/or EPA Region IX may be involved.

- Various other local approvals may be required, including approvals for ammonia storage tanks (if SCR is used), noise or odor regulations, coastal zone compliance or zoning changes. Many of these may be regulated by the City of Chula Vista. The MEU Study Team recommends that these issues be addressed if and when a more specific plan is developed.

2. Federal Regulatory Framework

a. Federal Energy Regulatory Commission

With certain exceptions not relevant to the scope of this feasibility analysis, the regulation of "Public Utilities" is vested in the FERC under the Federal Power Act (FPA) (16 USC § 824 et seq.). Section 201(f) of the FPA specifically exempts publicly owned and operated utilities. That Section provides:

> **(f) United States, State, political subdivision of a State, or agency or instrumentality thereof exempt**
>
> No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agency, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

Thus, if Chula Vista forms and operates an MEU, it will not be subject to the rate and service jurisdiction of the FERC.

That said, the rate and service jurisdiction of the FERC will inevitably impact Chula Vista and its operations inasmuch as the Chula Vista MEU will be transacting business with utilities which are subject to the jurisdiction of the FERC (e.g. SDG&E, SCE, PG&E and the CAISO). The rates for all utility services provided by regulated utilities (e.g. transmission service, partial or full requirements wholesale electric service and the provision of ancillary services) are all regulated by the FERC. Thus, to the extent that the Chula Vista MEU transacts business with any regulated utility, it will be drawn into the Federal regulatory process to the extent that it wishes to participate to protect its interests or challenge the justness and reasonableness of any rate or service provided or offered by the regulated utility.

It is also relevant to point out that, under the FERC's Order No. 888, all regulated utilities must provide access to their transmission facilities. The Chula Vista MEU will be able to take advantage of the FERC's open access policy in gaining access to transmission facilities of regulated utilities. Here again, however, the FERC will set the rate for such transmission service.

To operate its distribution system, a Chula Vista MEU would be required to establish an interconnection with SDG&E. The FPA, as amended by the Energy Policy Act of 1992, makes provision for establishing an interconnection with a regulated utility in the event that the utility refuses to agree to an interconnection. (*See* FPA Sections 210-211, 16, USC §§ 824 i and j).

Under these provisions, the Chula Vista MEU would be required to file a good faith request with the FERC for an interconnection of their respective facilities with SDG&E. SDG&E would be required to respond to the request within sixty (60) days by submitting a proposed interconnection agreement. In the event that the parties cannot agree on the terms and conditions of the interconnection, Chula Vista would have the right to invoke the FERC's jurisdiction to establish the terms and conditions of the interconnection agreement and to determine what costs Chula Vista would be required to pay to SDG&E for the modification of the SDG&E system to accommodate the Chula Vista interconnection. The FERC, as part of this process, may also require the payment of SDG&E's stranded generation costs which result from the establishment of a Chula Vista MEU and the transfer of SDG&E's customers to Chula Vista.[9]

In all likelihood, if Chula Vista takes over, by acquisition or condemnation of SDG&E's electric distribution system, it will be required to establish more than one point of interconnection with SDG&E and will be required to pay any costs of reconfiguring SDG&E's system to allow it to continue to provide service to its own customers who are currently served over the existing distribution system. The latter costs are known as "severance" damages which

9 The cost implications involved in establishing an interconnection with SDG&E under FERC rules and regulations are discussed in Appendix B, Section II.C.3 at 33-35.

are normally awarded in the condemnation proceedings if the parties cannot agree on the necessary system modifications and the related cost responsibility for those modifications.

b. Participating Transmission Owners under the CAISO Tariff

If a MEU acquires and operates transmission facilities or transmission rights, it has the right to become a PTO under the CAISO Tariff.

There are distinct advantages and disadvantages to becoming a PTO under the CAISO Tariff, and there is a myriad of potential costs and charges that may be imposed on the MEU in transactions involving the use of the CAISO controlled transmission grid.

An entity choosing to become a PTO will be subject to numerous requirements under the CAISO Tariff. It is beyond the scope of this feasibility analysis to identify and analyze all potential obligations and costs associated with becoming a PTO. We have, nevertheless, identified the principle costs associated with becoming a PTO under the CAISO's Tariff in Appendix C hereto. *See* Appendix C, Section II.D. at 83-84.

Of the approximately 37 publicly owned utility systems and agencies in California, only the Cities of Vernon, Azusa, Anaheim, Banning and Riverside have elected to become PTOs.

In the event that Chula Vista elects to acquire and operate transmission facilities or acquires transmission rights, this option should be considered, possibly in the implementation phase of the Chula Vista feasibility analysis.

c. Pending Legislative and Regulatory Proposals

While still pending and in various stages of litigation or legislative consideration, there are several legislative and regulatory proposals which could, in the near term, impact the operation of a Chula Vista MEU or have a long-range effect on its cost of providing electric service and operating its utility system.

The following regulatory and legislative proposals are worth noting in the context of determining the kind of utility structure Chula Vista should develop for its MEU:

APPENDIX B
REGULATORY AND LEGISLATIVE ISSUES

(1) Federal Energy Regulatory Commission Standard Market Design, Docket No. RM01-12-000

On July 31, 2002, FERC issued a proposed rule to remedy undue discrimination and establish a "standard market design" (SMD) for wholesale energy markets under which the FERC, among other things, would provide for:

- Public utility transmission facilities to be operated by "Independent Transmission Providers;"
- Locational marginal pricing (LMP), a market-based rate method for congestion management;
- Tradable Financial Transmission Rights (also called Congestion Revenue Rights or CRRs) as a means to lock in a fixed price for transmission;
- Procedures to monitor and mitigate market power;
- Procedures to assure, on a long-term regional basis, that there are adequate transmission, generation and demand-side resources;
- Access charges to recover embedded transmission costs that would be a demand charge billed on a customer's load ratio share of the transmission provider's cost, and would be paid by any entity taking power off the grid;
- Public utilities that operate day-ahead and real-time energy markets and transmission systems must be independent of market participants;
- Standards for real-time and day-ahead energy markets;
- A new transmission pricing policy based in part on "participant funding;"
- A formal role for state representatives to participate in decision-making processes of regional transmission organizations or other regional security and reliability entities; and
- Explicit obligations in the pro forma tariff for transmission providers and customers to comply with standards to ensure system security and reliability.

On April 28, 2003, FERC issued a SMD White Paper in which it attempted to clarify its SMD proposal. The White Paper, while not compromising the core elements of the SMD model, including some form of locational pricing, promises greater regional flexibility, a formal role for the states, and a slower pace for SMD implementation.

Regardless of the form in which SMD is ultimately adopted or implemented, it will likely continue to drive the FERC's decisions on issues such as energy market design, market power, regional transmission organizations, rates and terms of transmission service, transparency, generation and transmission infrastructure, and state-federal relations.

(2) California Legislation

Several California Senate and Assembly bills have been introduced in the past year that may alter the findings and recommendations included in this Report and affect the operations of a publicly owned utility. None of these bills has been adopted, but all remain active.

- **Senate Bill No. 888 (Dunn) (SB 888):** Also known as the "Repeal of Electricity Deregulation Act of 2003," SB 888 would make wholesale changes to the primary restructuring legislation (AB 1890), including the provisions related to direct access. The bill failed in the Assembly's Utilities and Commerce Committee on July 20, 2003, making it a two-year bill, and unless it is subject to a waiver of the Rules, it cannot be heard again until January 2004.

- **Senate Bill No. 119 (Morrow) (SB 119):** Last amended in April 2003, SB 119 is intended to permit the CAISO to more closely monitor the wholesale electric market. The bill would require a local publicly owned electric utility that sells or purchases wholesale electric energy or wholesale electric capacity in the state to provide certain sales transaction information to the CAISO. The bill would require a local publicly owned electric utility that owns transmission rights in the state to provide to the CAISO certain information regarding those rights. The bill would authorize the Attorney General to obtain from the CAISO that transactional and transmission information regarding the market activities of electrical corporations and any other market participants. Additionally, subject to certain restrictions, the bill would authorize the CAISO and the Attorney General to convey the information to another state agency, and would authorize the Attorney General or other state agency in possession of the information to convey the information to a federal government agency or a federally regulated entity that does not sell or purchase electric energy or capacity at wholesale. The new duties for local publicly owned electric utilities included in this bill would impose a state-mandated local program.

- **Senate Bill No. 697 (Soto) (SB 697):** Existing law requires a community choice aggregator to file an implementation plan with the CPUC in order for it to determine a cost-recovery mechanism to be imposed on the community choice aggregator to prevent a shifting of costs to an electrical corporation's bundled customers. SB 697 would require the CPUC, upon the filing of a petition or other appropriate procedure determined by the CPUC, and upon meeting of certain conditions, to establish separate distribution service rates and charges by an electrical corporation, for electricity, from an eligible renewable electricity generation source that is supplied to end use customers by an electric service provider pursuant to an implementation plan with a community choice aggregator, where the electricity is transported within a single local distribution system. The separate distribution charge would, to the extent permitted by federal law, avoid charges for transmission services and would specify how any applicable transmission charges would be allocated. The separate distribution charge would pass on any distribution system cost savings resulting from the development of distributed energy resources to the end use customer of the community choice aggregator. The bill would further limit the imposition of fees and charges by the CAISO.

- **Assembly Bill 816 (Reyes) (AB 816):** AB 816, as introduced, included specific language confirming the applicability of a cost responsibility surcharge on Municipal Departing Load, specifically new load located in previously undeveloped areas. The bill also contained an unrelated provision resurrecting direct access. Due to competing bills presented in the Senate, AB 816 was essentially rewritten several times, with the last draft deferring to the CPUC on the issue of application of the CRS to Municipal Departing Load, so long as the CPUC adopted a decision that did not allow customers to escape their "fair share" of the Department of Water Resources Charges. An apparent victim of politics, AB 816 is now a "two-year bill," meaning that absent a rule waiver, it cannot be heard again until January 2004.

II. EXERCISE OF THE POWER OF EMINENT DOMAIN

A. Eminent Domain Proceedings

The California Eminent Domain Law[10] requires that the condemnation follow the following basic steps in initiating and prosecuting a condemnation proceeding:

Offer: The public entity or municipality must make an offer to the property owners. This offer must reflect what the public entity or municipality believes is just compensation for the property.

Notice and Hearing: Prior to issuing a resolution of necessity, the public entity or municipality must provide, to the property owners, notice and opportunity to be heard with regard to public interest, public good, and the necessity of the property's acquisition.

Recommendation: After holding the necessary hearing, the governing body of the public entity (normally the legislative body of the public entity) must issue a written summary of the hearing and a written recommendation as to whether to adopt the resolution of necessity.

Resolution of Necessity: The governing body may then issue a resolution of necessity

Final Offer: At least 30 days prior to trial, the public entity must file its final offer and the owner must file its final demand.

Commencement of Eminent Domain Proceeding: After issuance of a resolution of necessity, the public entity must file a complaint with the superior court.

While Chula Vista would have the legal right to exercise its power of eminent domain to acquire the utility assets of SDG&E within the City, it is very important that cognizant officials of the City are aware of significant provisions of the eminent domain laws which give the property owner the right to challenge the City's Resolution of Necessity.

Under the Eminent Domain Law the City, in developing its proposed utility project and its plan to condemn the property of SDG&E, must establish (a) the public interest and necessity of the project, and (b) demonstrate that the proposed project is compatible with the greatest public good and least private injury. The City must then attempt to negotiate the

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10 Cal. Civ. Proc. Code § 1240.030.

purchase of the property from the owner for an amount the City believes to be just compensation.[11] And finally, the City must give SDG&E a reasonable opportunity to appear and be heard on these matters before Chula Vista initiates an eminent domain proceeding.[12]

A City Resolution of Necessity to condemn the property of an electric utility creates a rebuttable presumption that the matters set forth in the Resolution of Necessity are true.[13] Significantly, if the City is unable to reach agreement with SDG&E on the acquisition and elects to proceed over SDG&E's objection, SDG&E has the right to initiate a judicial review of the validity of the matters addressed in the Resolution of Necessity either before or during the eminent domain proceeding.[14] In that proceeding, SDG&E can object to the condemnation and attempt to demonstrate that the City has failed to establish that the public interest and necessity require the proposed project and the taking of the owner's property.[15]

Thus, if SDG&E elects to challenge Chula Vista's project, including the commendation, Chula Vista must be prepared to demonstrate that the public interest standard has been met. This can only be accomplished by a showing that the public benefits accruing from the project (*i.e.*, both (1) measurable financial benefits including utility rate reductions to utility customers in the City and revenue to the City to offset the loss of franchise fees and tax revenues; and (2) additional benefits including local control of utility services, utility price stability, enhanced utility reliability and increased opportunity for economic development in the City) are sufficient to meet the public interest standard and to show that the public interest is best served by allowing the project to proceed.

Chula Vista's success in any proceeding initiated to challenge the Resolution of Necessity will depend heavily on the strength of the feasibility study upon which the City relies in determining to proceed with condemnation. It is the opinion of the MEU Study Team that Chula Vista's chances of meeting the public interest standard will be greatly enhanced if, before electing to acquire the SDG&E distribution system, the City successfully initiates both Greenfield and CCA programs and can show both a history of successful development and management of these projects and positive financial benefits flowing from the City's projects.

Assuming that Chula Vista is successful in overcoming any threshold challenge to the Resolution of Necessity, it may proceed with the condemnation and, at the time of filing the complaint or at any time thereafter but prior to entry of judgment, the City may apply ex parte to the court for an order for possession pursuant to Cal. Civ. Proc. Code § 1255.410. The court will

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11 Cal. Govt. Code § 7267.2.

12 Cal. Civ. Proc. Code § 1245.235.

13 Cal. Civ. Proc. Code § 1245.250.

14 Cal. Civ. Proc. Code § 1245.255.

15 Cal. Civ. Proc. Code §§ 1250.550 and 1250.370.

authorize the public entity to take possession if it is entitled to take the property by eminent domain and has deposited with the court the probable amount of compensation as required by Cal. Civ. Proc. Code § 1255.010 – 1255.080. By taking such possession, the condemnor does not waive the right to appeal the judgment.

The acquiring public entity or municipality may elect to file a petition with the CPUC to request the CPUC to determine just compensation and certify the award to the superior court. Alternatively, the acquiring public entity or municipality may elect to allow the superior court to determine just compensation. Given the CPUC's recent decisions which exhibit antipathy towards unregulated publicly-owned utilities, it is the opinion of the MEU Study Team that Chula Vista should allow the superior court to determine just compensation rather than filing a petition to invoke the jurisdiction of the CPUC.

B. Valuation Methodologies

With respect to standards for determining "just compensation," California is a "fair value" state and the condemnee must receive the "fair value" of the facilities taken in eminent domain. There are numerous methodologies for determining "fair value" or "just compensation" none of which can be mandated as a single standard under state law. The courts have uniformly ruled that all recognized methods of valuation must be considered if presented. These range from depreciated net book value to replacement cost less depreciation methodology. These two methodologies set the parameters of utility property valuation. The lowest possible value will likely result from the application of depreciated net book value methodology, while use of a replacement cost new less depreciation methodology will likely produce the highest award. While it is impossible to predict, condemnation awards generally reflect values which are from 1.5 to 2.0 times the net book value, but far less than a value reflecting replacement cost new less depreciation.

The following are the most widely used methods of valuing utility assets for purposes of condemnation and arriving at a conclusion as to what is "just compensation."

1. Original Cost

Original Cost is derived from the values indicated on a company's accounting records and presented on its balance sheet. Such value, for regulatory purposes, is the cost of the asset (plant) when first devoted to public service (original costs), less depreciation. This means that the value of a company's physical plant, according to its accounting records, is based on the actual costs incurred to initially install electric facilities (typically years earlier).

2. Capitalized Earnings Method

The capitalized earnings method for determining value involves estimating the current value of future earnings derived from the asset. This method is often used for placing value on an on-going business concern, and is based on the premise that the value of the business is derived solely from its ability to sell its product or services at a profit in future years. Corporations often buy other corporations or a division of those corporations for a purchase price determined on the basis of future earnings. In this case, the sale of electricity could be treated as a distinct business enterprise resulting in a value based on capitalized earnings. This method differs from other methods in that it does not reference specific property or assets. Rather, there is an implicit assumption that in return for the purchase price, the acquiring entity will receive all of the assets necessary to achieve the projected level of future earnings. In the case of an electric distribution utility, these assets include land and land rights, and associated substation and distribution facilities. The capitalized earnings approach to valuation is dependent on the full complement of assets being acquired. Accordingly, calculation of a capitalized earnings value does not include damages resulting from numerous factors such as loss of economies of scale.

3. Replacement Cost New

Replacement cost new (RCN), as its name implies, involves calculating the current cost of replacing the plant in question with another identical plant. Replacement cost new less depreciation (RCNLD) is RCN less applicable deductions for depreciation. The major element that is considered in developing the RCNLD method is the cost of replacing the existing facilities. The calculation involves the following:

- Determination of original cost values as set forth above
- Adjustment of original cost value to current cost value (RCN)
- Adjustment of replacement costs new to account for depreciation (RCNLD)

RCNLD is a method that adjusts asset values solely by age and ignores existing maintenance. When used alone, the approach does not explicitly consider the condition of the existing plant, accounts receivable, or other factors that might increase or reduce the market value. It is appropriate that some factor be applied to RCN to reflect the actual condition of the facilities being acquired. This factor is referred to as "percent condition" and is analogous to the factor a used automobile buyer may apply to the purchase price to reflect the condition and maintenance performed on the automobile.

4. Percent Condition

Percent condition is an approach often used in appraisals. It is particularly applicable to most electric utility assts. The percent condition of a circuit breaker, for example, theoretically lies between 0 and 100 percent. A new circuit breaker would represent 100 percent condition. A circuit breaker that is 15 years old, but has just undergone a complete overhaul in which all existing major components were replaced with brand new components would also represent a 100 percent condition. Equipment that has failed or is in danger of eminent failure would be represented as zero percent condition. Generally, equipment that is operating properly would be rated between 50 and 100 percent condition depending on state of repair and where the equipment lies in its maintenance cycle. Accordingly, percent condition, when applied to U.S. electric utility property, results in a value less than RCN. Assuming normal maintenance, RCNLD and percent condition would yield similar valuations.

C. Cost Exposure

In the event that Chula Vista elects to form and operate an MDU through the acquisition or condemnation of SDG&E's electric and/or gas distribution system, it will be exposed to several classes or types of costs which must be taken into consideration in determining whether or when to proceed with this undertaking.

1. Acquisition Costs

As discussed in Section IV.F.4.a, if Chula Vista elects to attempt to acquire SDG&E's distribution system and related utility assets within the City, it must first make an offer to SDG&E in an amount which Chula Vista believes is just compensation for the property to be acquired.

In the event that the City and SDG&E cannot agree on the amount of compensation, the City may initiate condemnation proceedings under the procedures described above. As previously explained, once Chula Vista files its complaint with the superior court and initiates the condemnation proceeding, it may elect to have either the superior court or the California PUC determine the just compensation for the facilities to be taken.

As discussed in Section IV.F.2.a(1) at 101 and Appendix C, Section II.E.2 at 84-87, based upon a preliminary analysis of SDG&E's electric distribution system as reflected in public records, the MEU Study Team has estimated that the acquisition costs for SDG&E's utility distribution system in Chula Vista would amount to approximately $170,000,000 based on an RCNLD analysis and national distribution utility standards.

2. Severance Costs

In addition to awarding just compensation for the facilities acquired by Chula Vista, the superior court also has the jurisdiction to award severance damages to SDG&E for those costs which are incidental to the taking, but are not attributable to the value of property taken by the City. For example, if SDG&E maintains offices, or maintenance or other facilities which are located in Chula Vista but which are not taken by the City, the Company would be entitled to severance damages for the unrecovered costs of removing, relocating or closing facilities which are no longer of use to the Company. Severance damages may also include those costs which must be incurred by SDG&E to reconfigure its electric system in a manner which will allow the company to continue to serve its remaining customers who, prior to the establishment of Chula Vista's new service territory, were served over the same distribution facilities.[16] At this juncture, no detailed separate analysis has been made of the potential severance costs which may be awarded in the condemnation proceeding. The MEU Study Team has modeled a preliminary estimate of $10 million for severance and interconnection costs. A detailed estimate would be made during the Focused Feasibility and Implementation Plan, when and if Chula Vista elects to proceed with the acquisition of the distribution system.

3. Interconnection Costs

Under Sections 202(b), 210-212 of the FPA, the FERC has the authority to order a jurisdictional utility to interconnect with another electric system and, if necessary, to provide transmission service to the requesting party.

Section 202(b) of the FPA provides, in relevant part, that, upon application of any person engaged in the transmission or sale of electric energy, whenever the Commission:

> finds such action necessary or appropriate in the public interest it may by order direct a public utility (if the Commission finds that no undue burden will be placed upon such public utility thereby) to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: *Provided*, that the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

Section 202(b) also permits the Commission to prescribe the apportionment of costs, compensation, terms and conditions of the parties' arrangements.[17]

Section 210(a)(1) of the FPA provides, in relevant part, that upon application of an electric utility:

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16 As discussed in Section II.C.3, below, the FERC has the authority to establish the terms and conditions of the interconnection between SDG&E and the new Chula Vista distribution system. Thus, much of the system reconstruction costs will be included in the FERC award for interconnection costs.

17 *See Illinois Municipal Electric Agency*, 86 FERC ¶ 61,045, at 61,175 (1999).

> [T]he Commission may issue an order requiring—
>
> (A) the physical connection of … the transmission facilities of any electric utility, with the facilities of such applicant.
>
> (B) such action as may be necessary to make effective any physical connection described in subparagraph (A), which physical connection is ineffective for any reason, such as inadequate size, poor maintenance, or physical unreliability…
>
> (C) such increase in transmission capacity as may be necessary to carry out the purposes of any order under subparagraph (A) or (B).

Section 210(c), however, limits the Commission's ability to order interconnection, providing that:

> No order may be issued by the Commission under Subsection (a) unless the Commission determines that such order---
>
> (1) is in the public interest,
>
> (2) would—
>
> (A) encourage overall conservation of energy or capital,
>
> (B) optimize the efficiency of use of facilities and resources, or
>
> (C) improve the reliability of any electric utility system or Federal power marketing agency to which the order applies, and
>
> (3) meets the requirements of Section 212.

Section 212(c)(1) provides that, before issuing a final order under Section 210, the Commission shall issue a proposed order setting a reasonable time for the parties to agree to terms and conditions for carrying out the order, including the apportionment of any compensation for costs.[18]

In addition to these statutory provisions, it is relevant to point out that, pursuant to FERC Order No. 888, SDG&E has filed with the FERC an Open Access Transmission Tariff (OATT)[19] under which Chula Vista may request any necessary transmission service once it

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[18] *Id.* at 61,176.

[19] Filed July 1997 in FERC Docket No. OA97-664-000.

establishes its interconnection with SDG&E and compensates SDG&E for all just and reasonable costs of establishing the interconnection. The cost of transmission service, unless otherwise agreed to by the parties, will be governed by the terms of SDG&E OATT. The OATT provides that the transmission customer must agree to compensate SDG&E for any necessary transmission facility additions as long as such costs are consistent with FERC policy. See SDG&E OATT, Section 27.

In the event that SDG&E denies Chula Vista an interconnection and transmission service under its OATT, Chula Vista can seek that FERC order interconnection pursuant to Sections 210, 211 and 212 of the Federal Power Act. Chula Vista must demonstrate that the interconnection is in the public interest, which is shown by demonstrating that the availability of transmission service enhances competition in power markets by increasing power supply options of buyers and power sales options of sellers, and ultimately leads to lower costs to consumers. FERC has further determined that the public interest is served when the interconnecting utility is fully and fairly compensated for the costs it incurs in connection with the requested interconnection, and there is no unreasonable impairment of reliability. *See Illinois Municipal Electric Agency v. Illinois Power Co.*, 86 FERC ¶ 61,045 at 61,176 (1999) and *Sierra Pacific Power Company*, 89 FERC ¶ 61, 234 at 61,693 (1999).

Section 212(c) establishes the following procedures in processing an application: (1) upon a determination that the application meets the requirements to support interconnection under section 210 or 211, FERC will issue a preliminary order directing the interconnecting utility to interconnect the utility seeking an interconnection; (2) FERC then will set a reasonable time for apportionment of an compensation of costs:

> If the parties to the proposed interconnection order are able to agree, [FERC] will issue an order reflecting the agreed-upon terms and conditions if [FERC] approves of them. If the parties to the proposed interconnection order are unable to agree within the allotted time, the Commission will prescribe the apportionment of costs, compensation, terms, and conditions of interconnection.

Sierra Pacific at 61,694.

4. California Cost Responsibility Surcharge for Departing Load

The California Legislature and the CPUC have attempted to deal with the impact of the electric industry restructuring in general and, specifically, the rate impact occasioned by the enactment and implementation of Emergency Legislation[20] on January 17, 2001, which required that the California Department of Water Resources (DWR) assume responsibility for

[20] *See* Senate Bill 7, First Extraordinary Session (SB 7X).

procuring electricity on behalf of customers of the California investor-owned utilities. On February 1, 2001, the Legislature enacted AB 1X, which authorized DWR to continue to meet the utilities' net short requirements through December 31, 2002.[21] Pursuant to this legislation, the CPUC initiated a proceeding (Rulemaking 02-01-011) to prevent or minimize cost shifting for direct access customers. As discussed above, that proceeding has since expanded to also address cost shifts that would occur if a newly formed "publicly-owned utility" ceases to buy its requirements from the California investor-owned utilities and procured power by self-generation or purchases from other sources to provide electricity to customers within its service territory.

Pursuant to the Commission's MDL Decisions, on July 10, 2003, the CPUC issued an "Order Adopting Cost Responsibility Surcharge Mechanisms for Municipal Departing Load."[22] If Chula Vista forms an operating MEU and begins to generate power or purchase power from an entity other than SDG&E it will be responsible for paying an apportioned share of SDG&E's DWR-related costs as Municipal Departing Load.

Although the CPUC does not have general rate and service authority over publicly owned utilities, in the MDL Decisions, the Commission found that it does have the authority under AB 1X and AB 117 to impose a "cost responsibility surcharge" (CRS) on Municipal Departing Load to cover DWR-related costs (including both bond charges for past purchases and the obligations of long term contracts entered into by DWR) if the customers took bundled utility service on and after February 1, 2001 from an IOU, of if the customer is located in an area that was part of the IOUs' service territory on or after February 1, 2001 and therefore likely included in the load forecasts provided to DWR.

In the case of SDG&E, the Municipal Departing Load CRS has three components: (1) DWR Bond charges; (2) DWR Power Charge; and (3) a "Tail Competitive Transaction Charge," which is applicable to all Municipal Departing Load Customers in the investor-owned utility service territories as of December 20, 1995. These charges would continue to apply to SDG&E Municipal Departing Load Customers until these costs are fully recovered by SDG&E or until the charges are no longer assessed to the investor-owned utilities, including SDG&E.

As the law currently stands, load that falls within the meaning of "Municipal Departing Load" is subject to the cost responsibility surcharges imposed by the MDL Decisions. It is worth pointing out that the MDL Decisions have been the subject of petitions for writ of review filed with the California Supreme Court. Moreover, the contracts and costs which give rise to the CRS are the subject of a number of lawsuits in the state and federal courts and in proceedings before the FERC. The outcome of any of these legal proceedings may change the nature, amount, and applicability of the CRS.

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21 SDG&E began purchasing power through DWR on February 7, 2001.

22 *See* CPUC Decision 03-07-028.

The MEU Study Team analysis assumes that the CPUC will impose exit fees on the City for costs associated with uneconomic utility retained generation and power purchase contracts, DWR power purchase contracts, and bond charges from DWR financing of past power purchases. Exit fees are assumed to apply in all cases of CCA, Greenfield, and MDU development, consistent with the CPUC's proposed and final decisions in rulemaking proceeding R.02-01-011. Any changes to this assumption would impact the results of the analysis.

Based on these assumptions, the exit fees used in the analysis are derived from the exit fees applicable to direct access customers. The MEU Study Team used the annual exit fee projections from the capping phase of direct access surcharge proceeding, R.02-01-011 using the DWR modeling scenario identified by the Administrative Law Judge as the most reasonable scenario in her May 20, 2003 Proposed Decision (Scenario 14). Exit fees for direct access customers are capped at 2.7 cents per kWh. The cap was adopted by the CPUC to meet the objective of maintaining the viability of existing direct access contracts. The cap is not assumed to apply to CCA and future MEU activities, and the full, uncapped exit fees were included in the feasibility analysis. For SDG&E, the full cost exit fees are expected to be below the cap.

a. Direct Access Cost Responsibility Surcharge

Decision 02-11-022, issued on November 7, 2002, established the methodology for determining the Direct Access Cost Responsibility Surcharge (DA CRS) and related policy issues. The DA CRS is currently being used as a benchmark for the determination of both the MDL CRS and a CRS that would be applied to CCA customers. The actual calculations for 2003 are to be made following implementation workshops, once the final DWR historical costs and 2003 revenue requirements are known. The DA CRS is determined separately for each utility and will be updated annually as part of the DWR revenue requirement update. As of January 1, 2003 the DA CRS was set at the capped rate of 2.7 cents per kWh. The components of the DA CRS are:

- DWR bond charge. Applicable to all DA except for those who were continuously DA both before and after DWR began its power purchase program.
- DWR power charge for procurement costs between 9/21/01 and 12/31/02. Applicable to all incremental DA load that took bundled service on or after 2/1/01.
- DWR power charge for uneconomic portion of prospective (2003 and beyond) DWR costs. Applicable to all incremental DA load that took bundled service on or after 2/1/01.
- URG costs for market portion of Utility Retained Generation. Applicable to all DA customers.

b. Calculation of the DA CRS Components

(1) DWR Bond Costs

The DWR bond costs will be the same as charged to bundled service customers as determined in CPUC decision D.02-10-063.

(2) DWR Power Charges

DWR power charges (both historical and prospective) are calculated to keep bundled customers' rates unaffected by the migration of customers to direct access between July 1, 2001 - the suspension date for DA that was articulated in the Commission's proposed decision - and September 20, 2001, when DA was actually suspended pursuant to the final CPUC decision (D.01-09-060).

The DWR power charges are determined by production cost modeling using the difference in the average cost of the utility's total portfolio with and without the loads of incremental direct access customers. The DA CRS (excluding the DWR bond component) is set so that CRS payments by incremental DA customers offset the increase in cost of the portfolio. The DWR portion of the DA CRS is determined by subtracting the uneconomic URG costs component (i.e., CTC), described below, from the total DA CRS.

The DWR power costs for the historical period, which were funded by bundled service customers, will accrue interest on unpaid balances until repaid by DA customers. The DWR power charge for prospective costs will be implemented concurrently with the 2003 DWR power charges for bundled customers.

(3) Utility Retained Generation (URG) Cost*s*

The uneconomic URG costs are to be calculated by comparing the URG revenue requirement to a market value proxy based on the cost of a combined cycle gas turbine, using a 15-year depreciable life. For 2003, the market value proxy is 4.3 cents / kWh. The uneconomic URG costs are divided by total bundled and direct access sales to derive the URG component of the DA CRS. This implies stranded cost recovery for all utility generation and contracts, not just the "tail CTC" (Competition Transition Charge) components itemized in AB 1890. To the extent that the URG portfolio contains economic assets, inclusion of these assets will reduce the CTC. DA customers will also pay a relatively small cost component for employee-related transition costs as part of the ongoing CTC.

(4) DA CRS Cap

CPUC decision D.01-11-022 established that payments related to the DA CRS for DA customers are subject to an initial 2.7 cents per kWh cap through July 1, 2003. The revenue shortfall between the actual DA CRS and the cap will accrue interest at the rate applicable to DWR bonds.

On January 9, 2003, the ALJ issued a Ruling Scheduling Further Proceedings Regarding the DA CRS cap. As directed by D.02-11-022, the ALJ conducted further proceedings to determine whether, or to what extent, the cap should be revised after July 1, 2003 to ensure that shortfalls (plus interest) are recovered from DA customers over a reasonable time period. Despite an alternative decision proposed by Commissioner Lynch that would have increased the cap to 4.0 cents per kWh, in July 2003, the Commission issued Decision 03-07-030 retaining the 2.7 cent cap for another year.

(5) AB 265 Under-collection

AB 265 and CPUC implementing decisions required SDG&E to place a ceiling of 6.5 cents per kWh on the electric commodity rate for specified SDG&E customer classes, primarily residential, small commercial, and lighting customers, retroactive to June 1, 2000. SDG&E was required to establish an account to record the difference between the 6.5 cents per kWh rate ceiling and the actual commodity rate. The 6.5 cents per kWh rate ceiling expired on December 31, 2002. As of December 31, 2002, the under-collected balance was $215 million. The CPUC has allowed SDG&E to maintain its CTC at a level above cost-of-service to help reduce the AB 265 undercollection. Consistent with this practice, the MEU Study Team modeled SDG&E's CTC revenue requirement at the current $115 Million for 2003 and 2004, and any excess CTC revenue collected above the actual CTC costs are used to reduce the under-collections associated with the capping of customers' rates mandated by AB265. The CTC is assumed to revert to cost-of-service in 2005.

6. Federal Stranded Costs

In addition to state imposed exit fees and other nonbypassable charges, the City may be exposed to the payment of Federal stranded costs under the orders and procedures of the Federal Energy Regulatory Commission.

In its orders *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, the FERC established procedures for addressing the uneconomic sunk costs that utilities have prudently incurred under an industry regime that rested on a regulatory framework that was fundamentally altered. Under these procedures, FERC may require the departing customer of the utility to pay the utility's stranded costs, either as an exit fee or as a surcharge on the transmission services. FERC has determined that a utility can only seek recovery of stranded costs in those situations where a departing customer has obtained access to a new generation supplier through the use of the former supplying utility's FERC-required transmission tariff. FERC has established the following standards in determining whether a retail requirements customer which has become a wholesale distribution customer of a utility is responsible for the payment of stranded costs:

> [t]o be eligible to recover stranded costs from a departing customer, the utility must demonstrate that it incurred costs to provide service to the customer based on a reasonable expectation of continuing service to that customer beyond the contract term. In the case of stranded costs associated with wholesale requirements contracts customers, if the contract contains a notice of termination provision, that provision is strong evidence that the parties were aware that at some point in the future the customer might seek to find another supplier. Therefore, there is a rebuttable presumption of no reasonable expectation, and therefore no opportunity for stranded cost recovery unless the utility can overcome the presumption.

Order No. 888-A at 30,348. The rebuttable presumption must be overcome by the utility. FERC will consider "evergreen" or other automatic renewable provisions, whether state law awards exclusive service territories and imposes a mandatory obligation to serve, in determining whether the utility had a reasonable expectation to serve. Under the FERC's rates and its formula for computing stranded costs, the amount of stranded costs obligation can be no more that the average annual contribution to fixed power supply costs that would have been made by the departing generation customer had it remained a customer of the utility.

The implementation procedures for determining the stranded cost obligation are as follows: (1) the customer requests from the utility an estimate of the customer's stranded cost obligation, based upon the customer provided date that it is considering substituting alternative generation with that of the utility; (2) the utility has thirty days upon receipt of the request to respond to the customer with an estimate of the stranded cost obligation, including each component of the calculation and supporting detail to justify the amounts; (3) the customer will have thirty days to respond to the utility explaining which items, if any, it disagrees; and (4) if the parties are unable to agree on the stranded cost obligation, the customer can file with the Commission a petition for declaratory order or a Section 206 filing (the customer could also wait until the utility makes a Section 205 filing for stranded cost), seeking a Commission determination on the stranded cost obligation. The stranded cost obligation estimate does not become binding until either party initiates a proceeding with the Commission.

APPENDIX B
REGULATORY AND LEGISLATIVE ISSUES

The stranded cost obligation of Chula Vista will be dependent upon the types of generation contracts entered into by SDG&E on behalf of the load in Chula Vista, as well as any remaining generation interest held by SDG&E that is used to service Chula Vista. Presumably, restructuring under AB 1890, which required that SDG&E sell its generation assets, would have resulted in the mitigation of most of the potential stranded costs associated with generation owned by SDG&E. However, an actual stranded cost estimate would need to be obtained from SDG&E.

APPENDIX C

TECHNICAL APPENDIX

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I. ELECTRICITY SUPPLY

A. Regional Electricity Infrastructure

As discussed in other sections of this Report, the energy market in California and the country have undergone dramatic changes in the past several years. This section examines the electricity supply and demand for the southern California region and more specifically for the SDG&E service territory. Southern California is part of the Western Electricity Coordinating Council (WECC). The WECC is the interconnected electrical grid consisting of all or part of the twelve western states, two Canadian providences and a portion of Mexico. Actions in a portion of the WECC can and do impact the rest of the WECC.

The City and the service territory of SDG&E are part of the larger Southern California Market Area. The Southern California Market Area stretches from the border of the PG&E/SCE service territory in the north to Mexico in the south. SCE is the dominate utility in the region serving almost 60 percent of the approximately 33,000 MW load. However, the SDG&E and the Los Angeles Department of Water and Power (LADWP) are also large utilities within the Southern California Market Area.

The Southern California Market Area has a significant amount of existing infrastructure, both generation and transmission; however, the Southern California Market Area is very dependent on imports from other regions to meet its load requirements. Many of the existing generation units in southern California are over 30 years old and a significant portion of the transmission into the region is either committed to long-term agreements or is utilized to import Southern California Market Area utilities' resources located out-of-state. Due to the large load and age of the plants, there are numerous projects proposed for the Southern California Market Area. However, over the course of the last twenty-four months, several of these have been cancelled or at least put on hold. This has occurred for several reasons including regulatory uncertainty, financial problems of potential developers, renegotiation of contracts by the State of California, continued financial uncertainty of California investor-owned utilities, and the overall economic conditions.

1. Loads/Load Forecast

In 2002, the seventeen electric utilities in the Southern California Market Area had an estimated non-coincidental summer peak load of 33,500 MW. The Southern California Market Area peak load considered by this analysis represents the sum of the individual utility peak loads, not necessarily the coincidental peak load.

To estimate the demand for energy, the MEU Study Team developed a ten-year summer peak demand forecast for each of the utilities within the Southern California Market Area. The forecast was based in part on historical information regarding the peak demand of each utility, as well as information available from the CEC and the CAISO. For SDG&E the estimate is from the direct testimony of David M. Korinek in CPUC Rulemaking 01-10-024.[23] Overall, these sources indicate that the expected load growth for the Southern California Market Area is projected to increase at an average annual rate of 2.1 percent for the forecast period.

The two IOUs (SCE and SDG&E) that provide electric services within the Southern California Market Area serve approximately 69 percent of load with SCE meeting 57 percent and SDG&E 12 percent. SCE's load is estimated at 18,000 MW for 2002 and is projected to grow to 21,900 MW by 2011. SDG&E's load is estimated at 3,660 MW for 2002 and is projected to grow to 5,125 MW by 2011.

The publicly-owned utilities in the Southern California Market Area include municipal utilities, irrigation districts, water districts, and government agencies (e.g., California Department of Water Resources). In total, the publicly-owned utilities have a combined peak demand of approximately 9,950MW, or 31 percent of the Southern California Market Area for 2002. This load is estimated to grow to 11,000 MW by 2011. The largest municipal utility, LADWP, accounts for 55 percent of the non-IOU load and 16.5 percent of the total Southern California Market Area load.

For the purposes of this analysis, and consistent with the WECC standard reserve requirements, this analysis assumes a seven percent reserve margin requirement[24] for Southern California Market Area throughout the ten-year forecast period.

2. Resources

Resources available to meet demand requirements in the Southern California Market Area include (1) market area generation, and (2) transmission import capability. Existing market area generation is estimated to be approximately 29,000 MW in 2003. This includes the addition of over 2,300 MW that have been added to the system since 2001. The simultaneous transmission import capability is estimated to be approximately 13,000 MW throughout the 10-year forecast period.

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23 Direct Testimony of David M. Korinek, April 15, 2003, CPUC Rulemaking No. R.01-10-024, Presenting Information On Electrical Grid Reliability Criteria And Long-Term Planning Additions in SDG&E's Long-Term Resource Plan to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.

24 For SDG&E the reserve margin is 15 percent, which is in conformance with the testimony by Mr. Korinek.

a. Market Area Generation

Natural gas-fired units dominate existing Southern California Market Area generation. These units account for approximately 21,800 MW or approximately 71 percent of the existing generation in the Southern California Market Area. Table 1 summarizes the composition of the generation in the Southern California Market Area.

Table 1
Composition of Generation for
The Southern California Market Area

Fuel Type	Capacity (MW)	Percent of Total
Hydro	4,273	14%
Natural Gas/Oil	19,994	71%
Geothermal	36	0%
Nuclear	2,150	7%
Other	2,379	8%
Total	**28,832**	**100%**

b. Transmission Import Capability

Transmission imports into the Southern California Market Area play an extremely crucial role in meeting the needs of the region. Southern California Market Area utilities import a large amount of generation located in Nevada, Arizona, New Mexico, and Utah through the area's transmission system. Imports are necessary to "keep the lights on" in the Southern California Market Area.

Transmission imports to the Southern California Market Area are governed by the Southern California Import Transmission (SCIT) nomogram. The maximum non-simultaneous import capability into the Market Area is 18,564 MW. However, the SCIT nomogram currently limits simultaneous imports to approximately 13,000 MW, depending on multiple system conditions (including all units at Palo Verde being online and all transmission facilities being in-service and the amount of transmission flowing on the East of River (EOR) transmission system).

There are several different transmission paths that feed southern California, including transmission lines from northern California (Path 26), the Pacific Northwest (PDCI), the Desert Southwest (WOR), Utah region (Intermountain), and Mexico. Table 2 below identifies all of the major transmission paths into the Southern California Market Area.

Table 2
Non-Simultaneous Transmission Import Capability
Into the Southern California Market Area

Transmission Path	Capacity (MW)
West of River	10,118
Path 26	3,000
Pacific DC Intertie	3,100
Intermountain DC	1,920
Mexico Intertie	408

3. Proposed Generation

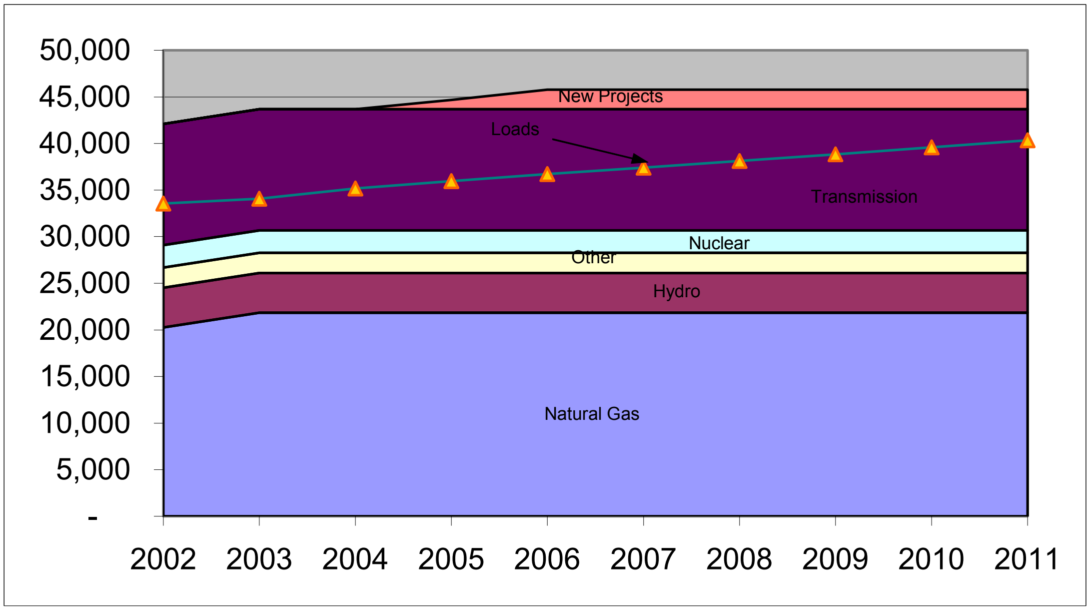
Over 4,100 MW of new generation (11 projects) are currently proposed for the Southern California Market Area, according to the CEC. The proposed projects are almost exclusively natural gas-fired generation. In addition, several thousand megawatts of proposed projects have either been terminated or put on-hold. It is anticipated that approximately half of the proposed new generation will ultimately be built in the Southern California Market Area.

Further complicating the analysis of the Southern California Market Area is the need to take into account the amount of generating capacity that would be out-of-service, whether for scheduled maintenance work, forced outages, or the lack of emission credits. To accommodate such an adjustment for the Southern California Market Area, the MEU Study Team reviewed power plant outage information provided by the CAISO to derive an outage adjustment factor for this analysis. Although it is important to note that plant outages vary throughout the year, especially during winter and spring periods as a result of planned maintenance activities, the outage factor of 10 percent used for this study is aimed to provide a conservative estimate of readily available generation resources.

a. Load/Resource Balance

Figure A below provides an illustration of the projected load/resource balance for the next ten-year period.

Figure A
Southern California Load/Resource Balance



b. SDG&E Load/Resource Balance

SDG&E meets the electric demand of its service territory through generation projects located within its service territory and by importing energy from outside its service territory using its transmission system and the CAISO Controlled Grid. Limited new generation or transmission projects have been added to SDG&E's system over the past several years; however, there are currently several projects (both generation and transmission) that are being considered to meet the needs of SDG&E's customers.

In 2003, the estimated peak load and reserve requirement for SDG&E's service territory is estimated to be 4,370 MW. This is expected to grow to over 5,000 MW by 2006-07. The SDG&E service territory is facing a resource shortfall by 2006-07 unless new resources are brought on-line.

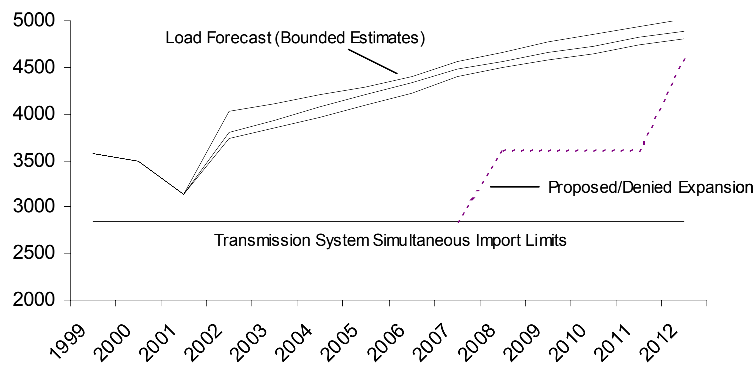
Existing Transmission Capacity

The SDG&E transmission system has a simultaneous import capability limitation (SIL) of 2,850 MW. Pursuant to the CAISO statewide standards, SDG&E transmission planning additions will increase SIL by 750 MW in 2008 and 1000 MW in 2012. If SDG&E's customer load exceeds these import limits, it must be supplied by local generation.[25] Existing and projected electric demand significantly exceeds existing and planned transmission import limits. The maps on the following pages highlight the

25 *See* Korinek Testimony, April 15, 2003, CPUC Rulemaking No. R.01-10-024.

existing SDG&E transmission system, the SDG&E proposed transmission projects, and finally the "cut planes" or limitations to imports into the SDG&E service territory.

Projected Regional Loads and Transmission Import Limits [26]



B. In-Area Generation

In addition to generation imports, SDG&E relies upon in-area generation to meet the electricity demands of its customers. In-area generation relies almost solely on the Encina and South Bay Power Plants.

The following table summarizes existing local area (on-system) generation capacity.[27] Resource planning portfolios are designed to meet peak loads plus a planning reserve margin of 15 percent each year. On-system generation capacity is currently approximately 2,000 MW short of meeting the region's 2002 load and reserve requirements.

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26 California Energy Commission (CEC) 2002 - 2012 California Energy Commission Staff's Outlook for the State - Tables E-1, E-2, E-3.

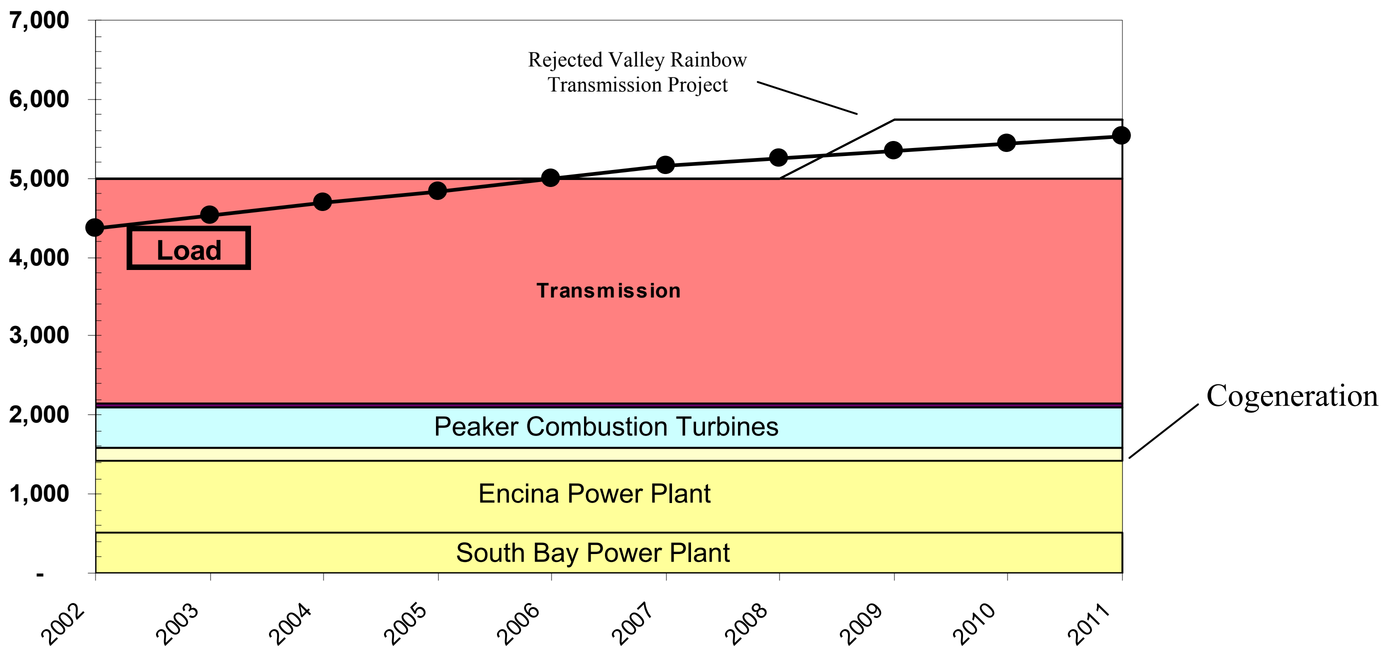
27 Direct Testimony of Robert B. Anderson, April 15 2003, CPUC Rulemaking No. R.01-10-024 Presenting SDG&E's Long-Term Resource Plan to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.

Electric Generation Plants in SDG&E's Area	MW
Encina and South Bay	1,635
Combustion Turbines	525
Renewable Power Plants	30
Cogeneration	170
Total Capacity	2,360
2002 Peak Load and Reserve Requirement	4,370
Local Generation Deficiency	2,010

Existing base-load generation resources in San Diego were placed in service in the mid-1950s to mid-1960s and are approaching retirement. As existing resources are retired and as regional load continues to grow, the capacity of indigenous generation to meet the region's needs is estimated at 55 percent in 2002, and may dip to 44 percent by 2010, 36 percent by 2020 and as low as 29 percent by 2030.[28] The following chart shows how regional resources, both transmission and on-system generation, will fall short of serving regional load as early as 2006.

[28] The San Diego Regional Energy Infrastructure Study (REIS) was commissioned by a multi-agency team consisting of the City of San Diego, the County of San Diego, the San Diego County Water Authority, the San Diego Association of Governments, the San Diego Regional Energy Office, the Utility Consumers Action Network and the Port of San Diego. The goal of the study was to develop a fact-based foundation for assessing the San Diego regions electricity and natural gas needs through 2030. The Study was completed by San Diego-based Science Applications International Corporation and can be found at http://www.sdenergy.org/

SDG&E Electricity Resource Balance



C. Regional Electric Energy Resource Balance Prospects to Expand Transmission Capacities

Existing and planned electric transmission system import capacities fall significantly below projected load growth in the SDG&E load area. This best-case scenario anticipates in-service dates for planned transmission upgrades assuming regulatory approval and construction lead times. In the past, as with the planned transmission upgrade of its new Northern Interconnection (subsequently named the Valley Rainbow Interconnect), the CPUC has demonstrated that its approval cannot be assumed.

The CAISO Tariff requires SDG&E to conduct an annual grid assessment and expansion study. The study covers a ten-year planning horizon and is conducted using a CAISO stakeholder process that allows for third party review and input. During the 1999 grid assessment study, SDG&E identified the need for a new Northern Interconnect, which was approved by the CAISO Board of Governors in May 2000. SDG&E subsequently filed a Certificate for Public Convenience and Necessity (CPCN) application for the project with the CPUC in March 2001.

After a 21-month proceeding, ending in December 2002, the Commission rejected SDG&E's application for a CPCN to build the Valley Rainbow transmission project.[29] SDG&E filed a petition for a rehearing which the CPUC denied in May 2003. SDG&E then asked that the case be reopened based on new evidence. The CPUC denied SDG&E's bid to reopen the case on June 5, 2003.

As illustrated above, resource planners can neither assume nor rely upon regulatory approvals of projects, notwithstanding demonstrated necessity by cognizant authorities. Given SDG&E's inability to successfully overcome the complex, lengthy and costly process of seeking approvals by the CAISO and the CPUC in pursuit of such projects, the MEU Study Team has a low level of confidence in similar transmission alternatives for the City. The sole remaining alternative lies in increasing local generation to meet the area's, and the City's, growing needs.

D. Planned Generation Resources

1. Otay Mesa Generating Project

The Otay Mesa Generating Project (Otay Mesa) will be a 510 MW, natural gas-fired combined cycle power plant located in the Otay Mesa area in western San Diego County. The 15-acre site is about 15 miles southeast of San Diego, California, and about 1.5 miles north of the United States/Mexico border.

A new 230-kV switchyard at the site is proposed. There are plans to build a 0.1-mile connection to SDG&E's existing 230-kV Miguel-Tijuana transmission line that passes near the eastern boundary of the Otay Mesa site. A new two-mile natural gas pipeline will be built by SDG&E to provide fuel for the project. Originally scheduled for completion in the summer of 2002, the construction schedule now calls for its completion by summer 2005. Currently the project is reported to be five percent complete.

A Master Power Purchase and Sale Agreement (MPPSA) was entered into on May 1, 2002 between the project owner, Calpine Energy Services, LP, and DWR setting forth the terms for the sale of Otay Mesa power output to DWR.[30] Under the agreement, Calpine must provide monthly reports to DWR setting forth any pre-construction activities (including permitting, licensing, financing, equipment acquisition and similar preconstruction activities), construction activities, progress toward compliance and any milestone dates established by the CEC or other applicable siting permit and expected commercial operation dates. Furthermore, under the agreement,[31] if Calpine elects not to proceed with development of the project or fails to achieve any major milestones, all rights, title and interests in Otay Mesa will transfer to DWR.

On May 9, 2003, Calpine filed a motion in CPUC Rulemaking 01-10-024, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for

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29 *See* the CPUC Decision (D 02-12-066) rejecting SDG&E's CPCN application for the Valley Rainbow transmission project.

30 The MPPSA can be found on DWR's website www.cers.water.ca.gov/newContracts.html

31 MPPSA Special Conditions (4)(a) (i) and (ii).

Generation Procurement, requesting the Commission provide expedited "*guidance and authority*" to SDG&E to immediately address its resource needs for 2005, including expediting discussions to secure an executed and approved long-term power purchase agreement. Comments supporting the request have been filed by the CAISO, the California Consumer Power and Conservation Financing Authority (Power Authority), and Save Southwest Riverside County. Comments opposing Calpine's motion have been filed by SDG&E, Sempra Energy Resources and Dynergy Marketing and Trading in addition to motions to intervene which were granted to InterGen and Peabody Western Coal Company, all of which have competing generation interests.

SDG&E has recently announced plans to purchase most or all of the capacity from Otay Mesa.

2. Palomar Energy (Escondido)

The proposed project consists of a natural gas-fired combined cycle power plant with a nominal electrical output rating of 546 MW and commercial operation planned for the summer of 2004. The project location is a 20-acre site within a planned 186-acre industrial park in the City of Escondido. The project includes a new 230-kV switchyard connecting with an existing SDG&E electric transmission line located immediately adjacent to the project site.

The project does not require construction of any new transmission lines and will be fueled with natural gas delivered via an existing SDG&E gas pipeline.

The project is being developed by Palomar Energy LLC (Sempra Energy[32]) under Certification Application (01-AFC-24), submitted on November 28, 2001. A CEC Staff Assessment dated January 24, 2003 concludes that all environmental and engineering impacts have been addressed to a level of insignificance. However, the CEC Staff has proposed mitigation of Air Quality and Visual Resources that has not been agreed to by the applicant. The project's estimated on-line date is April 1, 2005.[33]

3. South Bay Power Plant Repower (SBPP)

The California State Lands Commission approved the San Diego Unified Port District's (Port District or Port) expenditure of $110 million in public trust funds to acquire the SBPP from SDG&E on January 29, 1999. The existing SBPP consists of four natural gas-fired conventional boiler units and one 14-megawatt combustion turbine. The main generation units were placed into service between 1960 and 1971 as reflected below:

32 *See* California Energy Commission posting of Western Electricity Coordinating Council Area Proposed Generation sites.

33 *Id.*

South Bay Power Plant - In-Service Dates and Capacity

	In-Service Date	Capacity (MW)	Design-Life Retirement Projections Low	Design-Life Retirement Projections High	
Unit 1	1960	145	2000	2010	
Unit 2	1962	149	2002	2012	
Unit 3	1964	174	2004	2014	
Unit 4	1971	222	2011	2021	(retired)
Total		690			

Replacing the aging plant would increase regional natural gas efficiency, delay the need for natural gas pipeline capacity expansions, and improve air quality. The following chart shows the relative efficiency and emissions output of the SBPP compared with that of a modern power plant,[34] assuming SBPP's 2002 energy delivery. [35]

South Bay Power Plant Efficiency and Emission Output (Tons)

	Reference Heat Rate BTU/kWh	Nitrogen Oxide	Carbon Monoxide	Volatile Organic Compounds
South Bay Power Plant	10,300	87	518	35
Modern Power Plant	7,000	41	64	12
Modernization Reductions	32%	53%	88%	67%

Duke Energy North America's (Duke) 10-year lease with the Port District to operate the SBPP went into effect in April 1999. As part of its $110 million ten-year lease agreement with the Port District, Duke must dismantle and relocate the existing plant by 2009. According to the lease agreement, Duke must identify a specific relocation site no later than June 2006 and publicize its site selection as part of an application to the CEC for permits to site the new plant.

The City derives revenue [36] from having the SBPP on its bayfront and has requested that a replacement plant be built near the current one. The City Council voted in November 2001 to support relocating the plant just south of its current location at the adjacent (35+ acre) LNG site, anticipating that the new plant could provide a substantial revenue stream to help provide the infrastructure necessary to build out the Bayfront

[34] Prototypical combine cycle generating turbine plant consisting of a 2-on-1 (500 MW) and 1-on-1 (250 MW) power trains, using three GE 7FA combustion turbines, three Nooter Eriksen triple pressure reheat HRSGs and two GE steam turbines; includes five GE generator step-up (GSU) transformers.

[35] CAISO 2002 Reliability Must Run (RMR) energy delivery 1,163,501 MWH.

[36] San Diego County Tax Assessor's Office reflects 2002 depreciate plant value at $92.5 million and property taxes paid $989,650.

development area. The City's request is being considered as part of the Port Authority's master planning process. To date, Duke has screened about two-dozen sites, but has yet to disclose prospective sites claiming that such disclosure would alert real estate speculators, who would drive up property costs.[37]

Under Section II.C at 21-22, the MEU Study Team described in more detail why power plant ownership and/or entitlement to energy output is tied to the cost-effective operation of MEU structures examined in this report. However, potential operational benefits are inextricably linked to the underlying value to the City of having new power generation facilities located inside the Chula Vista tax rate area. Energy supply arrangements that promote and ensure such facilities will be located within the City's jurisdiction create value that must be captured in any cost-benefit equation.

Assembly Bill 81 (Migden) amended Property Tax Rule 905 on June 20, 2002, effective January 1, 2003, ensuring that cites hosting electric generation facilities will receive property tax revenue therefrom.[38] The effect of these actions is that the State of California Board of Equalization will value and assess forty-two electric generation facilities beginning with lien date 2003 including twenty older facilities divested by CPUC regulated utilities (such as SDG&E) and twenty-two new facilities. The property tax assessed value of an electric generation facility will be allocated entirely to that "tax rate area" in which the facility is located. In this case the Chula Vista tax rate area number is 0100.

Under this new rule, the value of the older divested as well as new plants is currently in the process of being assessed. The older plants are more difficult to value due to the weakness of using either the *replacement cost new less depreciation* (weakness: quantifying functional and economic obsolescence) or the *discounted cash flow income approach value indicator* (weakness: reliance on highly subjective future income estimates). The Board of Equalization will hold hearings between September and December 2003 to finalize power plant assessed values. However, for reference, in 2002 the assessed, depreciated, value of the SBPP was $92.5 million and property taxes paid by Duke were $989,650. New plants, such as the planned replacement for SBPP, will be valued based on their replacement cost new less depreciation.

The MEU Study Team estimates the capital cost for contemporary power plants (500-700 MW, with heat rates estimated at 7,000 BTU/kWh) to be $500 million. If such a power plant were built within the Chula Vista tax rate area, City tax revenue could be estimated at $3.23 million, annually. Depending upon whether the SBPP relocates inside or outside the City will determine whether the City loses approximately $0.745 million in tax revenue or gains $2.3 million in annual property tax revenue.[39] Accordingly, energy supply arrangements that ensure such facilities will be located

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37 Duke spokesman Patrick Mullen April 2003.

38 California Revenue and Taxation Code § 100.9 (a).

39 Based on analysis performed by Harrell & Company, provided by the City Community Development Department.

within the City's jurisdiction create value and this value must be captured in any cost-benefit equation, and considered when the City decides upon an ultimate course of action.

4. Significant Barriers to Power Plant Development

San Diego County is a non-attainment zone and new major emission sources must be met with offsets from other sources within the county. The San Diego Air Pollution Control District (APCD) Rule 20.3(d)(8) requires new stationary sources that will emit more than 50 tons per year of NOx and volatile organic compounds (VOC) to offset these emissions[40]. The availability of NOx emission reduction credits (ERCs) is limited in San Diego, which is a significant barrier to the building of new power plants. Banked ERCs can be purchased or an interpollutant trade of VOC ERCs is allowed by Rule 20.3(d)(5)(vi).[41]

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40 This requirement may soon be changed to a threshold of 100 tons per year.

41 Sempra Energy has acquired emission credits for its proposed Palomar Plant in Escondido through this mechanism.

II. FINANCIAL ANALYSIS ASSUMPTIONS AND PRO FORMA

This section of the Technical Appendix describes the methodology and assumptions used to derive the financial pro forma results.

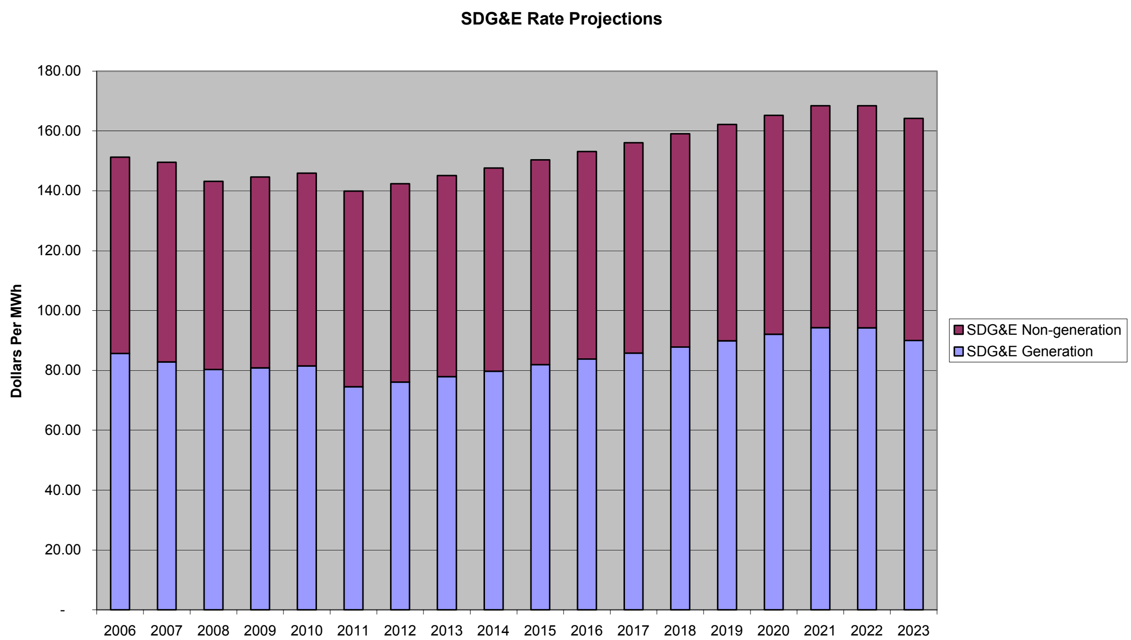
A. SDG&E Rates Forecast

SDG&E rates represent the reference point for cost savings created by implementation of an MEU. Generation rates are sensitive to changes in natural gas prices and changes in the composition of SDG&E's supply portfolio over time. It is not sufficient to simply escalate current generation rates at an assumed inflation rate. Rather, the MEU Study Team has developed a cost-of-service model to forecast the various costs that make up SDG&E's generation rates. These costs include: (1) Utility Retained Generation (URG) (including Qualifying Facility (QF) and Bilateral power purchase contracts); (2) DWR power purchase contracts; (3) CAISO charges for ancillary services and other charges; and (4) residual spot market purchases or sales.

The cost of service model enables consistency in assumptions regarding natural gas prices and other factor input costs between forecasted SDG&E rates and the costs of supplying a municipal portfolio, and facilitates a robust assessment of scenarios incorporating varying natural gas prices.

The following chart shows SDG&E's projected rates for generation and non-generation (delivery) services:

Chart 12: Projected SDG&E Retail Rates From 2006 Through 2023



SDG&E rates are projected to remain relatively flat or slightly decrease from 2006 through 2011 as a result of the gradual expiration of relatively high cost DWR contracts. Rates are projected to rise modestly from 2011 through 2023.

The components of SDG&E's revenue requirement are described below. In developing the rate forecast, any excess or shortfall between the resources available to SDG&E and SDG&E's load requirements (*i.e.*, the residual net short) are assumed to be sold to or purchased from the market at prevailing wholesale market prices.

1. Utility Retained Generation

As a result of implementing the state's generation divestiture policy in the late 1990s, SDG&E has retained an ownership interest in only one generation project, *i.e.*, its 20% share of the San Onofre Nuclear Generation Station (SONGS) units 2 and 3. Other resources in the utility retained generation portfolio are QF contracts and bilateral contracts that SDG&E signed with generators and power marketers.

SONGS capital and operating and maintenance costs were obtained from SDG&E's 2003 Cost-of-Service Filing with the CPUC (A.02-12-028). Annual SONGS capital additions were projected based on the projections presented by SCE in its 2003 General Rate Case (A.02-05-004) and were recovered over the remaining life of the plant based on current CPUC policy.[42] Nuclear O&M expenses and decommissioning costs were escalated according to the nuclear escalation factors contained in SCE's General Rate Case. These escalation factors vary by year and range from 2.06% to 2.95%.

Data for SDG&E's QF and bilateral power purchase contracts were obtained from the Company's 2002 FERC Form 1 filing. Approximately 67% of SDG&E's QF contracts are indexed to the price of natural gas, and these costs were adjusted on an annual basis for projected natural gas price changes. Contract quantities were projected to decline over time based on data previously reported by SDG&E and published in the consultant's report supporting the DWR bond financing issuance of October 23, 2002. [43]

URG costs were explicitly modeled through 2012. From 2013 through 2023, URG costs were escalated at a constant annual rate of 2.5%.

2. DWR Contracts

The MEU Study Team modeled the DWR contract quantities, operating dispatch parameters, and costs that were allocated to SDG&E in the CPUC's DWR Contract Allocation Decision (D.02-09-053). Each individual contract was analyzed to determine pricing terms for energy and capacity, MW quantities, and operating parameters or limitations. Operating hours for dispatchable contracts were modeled on a monthly basis, based on the individual unit's heat rate, natural gas prices, and other operating parameters specified in the contracts. DWR contract quantities allocated to SDG&E reach a peak in 2004 and decline to zero by 2013. The declining DWR contract volumes are assumed to be replaced with purchases at the prevailing market prices.

3. Non-Generation Rates

Non-generation rates include charges for transmission, distribution, and public purpose programs. These charges are assumed to escalate at an annual rate of 1.3% per year, starting with SDG&E's current non-generation rates as of June 2003 as the base. The Fixed Transition Amounts, which are the payments for the 1997 rate reduction bonds that financed the 10% rate reduction provided to residential and small commercial customers, are assumed to continue at the current levels until 2007, when these charges are removed from residential and small commercial customer rates.

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[42] SCE is the majority owner and operator of SONGS. Current CPUC practice is to determine the costs of SONGS in SCE's General Rate Cases and then assign a portion of SONGS costs to SDG&E's based on its ownership share of the plant.

[43] *See* Official Statement, State of California Department of Water Resources, Power Supply Revenue Bond, dated October 23, 2003, at Appendix A.

4. AB 265 Under-Collection

AB 265 and related CPUC implementing decisions required SDG&E to place a ceiling of 6.5 cents per kWh on the electric commodity rate for specified SDG&E customer classes, primarily residential, small commercial, and lighting customers, retroactive to June 1, 2000. SDG&E was required to establish an account to record the difference between the 6.5 cents per kWh rate ceiling and the actual commodity rate. The 6.5 cents per kWh rate ceiling expired on December 31, 2002. As of December 31, 2002, the under-collected balance was $215 million. The CPUC has allowed SDG&E to maintain its rates above cost-of-service to help reduce the AB 265 under-collection. Consistent with this practice, the MEU Study Team modeled SDG&E's Competition Transition Charge (CTC) revenue requirement at the current $115 M for 2003 and 2004, and any excess CTC revenue collected above the actual CTC costs are used to reduce the under-collections associated with the capping of customers' rates mandated by AB 265. The CTC is assumed to revert to cost-of-service status in 2005.

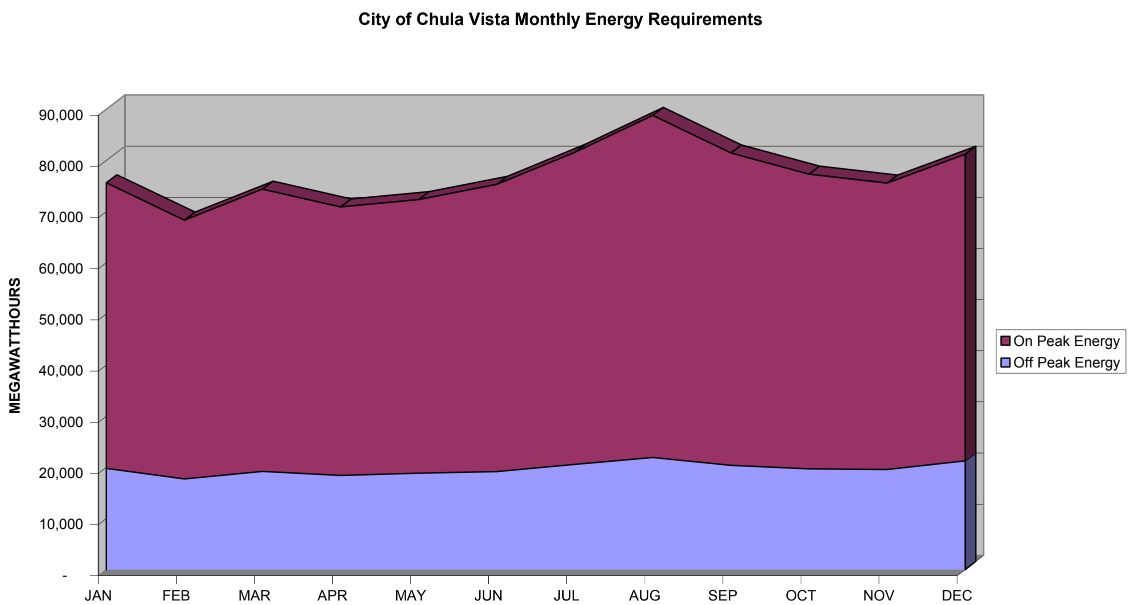
B. Electric Supply Costs

Under any MEU scenario, the City would need to produce or procure electricity to serve the load requirements of some or all of the electric customers within the City. The primary cost drivers of electric supply costs are (1) the load profiles of the MEU customers, and (2) the resources used to form the City's electric supply portfolio.

1. Load Profiles

The MEU Study Team constructed a composite load shape for Chula Vista reflective of the City's customer mix and load profiles. The major customer classes within the City comprise residential (SDG&E Class Load Profile DR), small commercial (SDG&E Class Load Profile A), medium commercial (SDG&E Class Load Profile AL-TOU, <500 KW), large commercial/industrial (SDG&E Class Load Profile AL-TOU, > 500 KW), and Street Lighting. The model assigns the annual projected kWh usage for each customer class to each hour in the year using SDG&E's hourly load profiles for the appropriate customer class. The class profiles are combined to form a composite load shape for the City, and the composite load shape is summarized into monthly peak and off-peak periods to conform to the supply products available in the wholesale market. Load requirements are adjusted by distribution loss factors of 7% to represent transmission grid level load requirements. Total monthly peak and off-peak energy requirements projected for the City's first year of operations are shown in the following chart:

Chart 13: Projected Monthly Load Requirements Of Chula Vista In 2006



2. Electric Supply Portfolio

A variety of supply options can be utilized to meet the load requirements of the City. The City can hedge its exposure to energy cost price risk through standard risk management techniques and instruments such as forward and futures contracts, capacity contracts or other financial derivatives.

The City could assemble a supply portfolio comprising varying amounts and types of resources including:

- Power purchase contracts (1 to 5 years) for peak and base load;
- Short-term contracts (quarterly up to 1 year in duration) for peak and base load;
- Renewable energy contracts for peak and base load, to comply with the Renewable Portfolio Standards mandated by AB 1078;
- Assignment of DWR contracts;
- Generation ownership; and
- Spot market purchases.

The MEU Study Team evaluated a number of supply portfolios to optimally serve the load requirements of the City. A typical supply portfolio would utilize generation owned by the City or long-term contracts for the majority of projected base load requirements. These long-term resources would be supplemented with short-term contracts covering the additional seasonal load requirements of the portfolio, typically in the third quarter of each year. Spot market purchases and sales are used to fill the residual net short load requirements.

Common criteria among the supply alternatives is to manage risk by limiting spot market purchases to 15% of the portfolio and ensure that the portfolio meets, at a minimum, the Renewable Portfolio Standards (RPS) mandated by AB 1078. The RPS requires that renewable energy resources make up at least 20% of the portfolio by 2017.

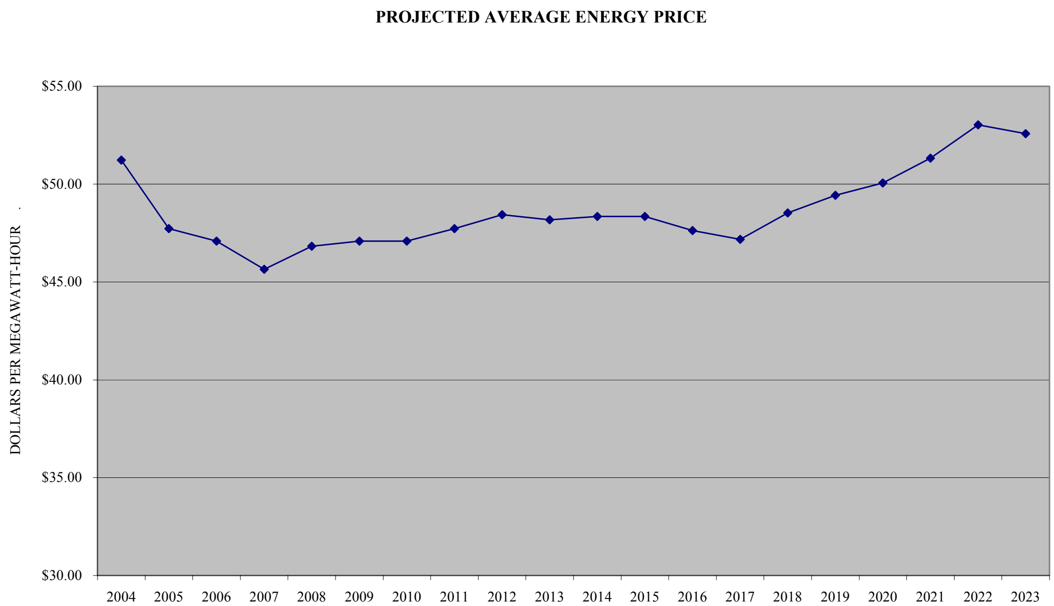
The two primary supply scenarios evaluated for the CCA and MDU options are (1) Generation Supply Strategy, and (2) Contracts Supply Strategy. Only the Contracts Supply Strategy was evaluated for the Greenfield option because it would not likely be feasible to obtain an ownership interest in a generation project to match the small and rapidly changing load requirements of the Greenfield development. The MEU Study Team also evaluated a portfolio containing a pro-rata allocation of DWR contracts, but found that the cost of such a portfolio would exceed the costs of the Generation or Power Purchase Contracts portfolios, including the exit fees related to bypassing the DWR contracts.

a. Spot Market Prices

The electric supply cost projections are based on a forward energy curve modeled using the costs of an existing gas-fired resource as a proxy for the hourly market-clearing price. The MEU Study Team's natural gas price projections used in creation of the forward energy curve are detailed in Appendix C in Sections III.D and E at 116-119. Peak and off-peak prices are derivatives of the projected baseload prices. Peak prices are modeled as 20% higher than average baseload prices, and off-peak prices are modeled as 20% lower than average baseload prices.

The projected average electricity prices for baseload energy are shown in the following chart:

Chart 14: Projected Average Electricity Prices For Baseload Requirements



Current natural gas prices are at historically high levels and are projected to remain so. If natural gas prices revert to lower levels, the City's cost savings would increase. Reductions in natural gas prices will have a greater mitigating effect on the City's electric supply cost of service relative to SDG&E's generation rates due to the existence of nuclear and fixed price contracts in SDG&E's supply portfolio whose costs are insensitive to the price of natural gas.

b. Power Purchase Contract Prices

Power purchase contract costs were modeled by developing a statistical relationship between published prices for forward peak contracts for energy in the South of Path 15 Congestion Zone applicable to Southern California and the modeled forward curve in 2005. The result is a 5% premium for fixed priced contracts relative to expected peak period spot market prices. This premium was extended along the forward curve to yield estimated contract costs for the entire study period. The modeled contract prices were independently validated against quotes obtained from the broker market for peak and off-peak annual contracts for 2004 and 2005, and found to calibrate to within 2% of these market quotes.

The Contracts Supply Strategy evaluated for the CCA and MDU options includes the following fixed priced contracts:

Power Purchase Contracts – CCA/MDU Options

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	50	49	5 Years
2006	Peak (6 x 16)	75	59	5 Years
2011	Base (7 x 24)	50	51	5 Years
2011	Peak (6 x 16)	75	61	5 Years
2016	Base (7 x 24)	75	51	5 Years
2016	Peak (6 x 16)	100	61	5 Years
2021	Base (7 x 24)	75	55	3 Years
2021	Peak (6 x 16)	125	66	3 Years

The electric supply portfolio evaluated for Greenfield includes the following fixed priced contracts:

Power Purchase Contracts - Greenfield Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	5	49	4 Years
2006	Peak (6 x 16)	10	59	4 Years
2010	Base (7 x 24)	12	50	5 Years
2010	Peak (6 x 16)	15	60	5 Years
2015	Base (7 x 24)	15	51	5 Years
2015	Peak (6 x 16)	25	61	5 Years
2020	Base (7 x 24)	20	54	4 Years
2020	Peak (6 x 16)	25	65	4 Years

c. Renewable Energy Contract Prices

Contracts for renewable power were modeled with a $3 per MWh premium to the contract price of non-renewable power. The MEU Study Team derived this premium from a historical analysis of "green ticket" [44] prices in California, as reported by the Automated Power Exchange, Inc. (APX). APX published prices for certificates for renewable power through December 2002, at which time the market was suspended pending CPUC implementation plan for SB 1078 (Renewable Portfolio Standard). The prices of the certificates represent the premiums paid to sellers of renewable power over and above the prices received by sellers of non-renewable power. The RPS requires that the portion of the portfolio supplied by renewable resources increase by 1% per year.

The CPUC has yet to determine how the standard would apply to a CCA, and it is not clear that a MDU would be required to meet the RPS. The MEU Study Team has assumed that the City's portfolio would match the minimum standards applicable to SDG&E in all of the MEU options. Accordingly, the portion of the portfolio comprised of renewable energy is established at 7% in 2006 and gradually increases to 20% in 2017, consistent with RPS requirements.

The following renewable energy contracts were assumed in the CCA/MUD and Greenfield portfolios for both the Generation and Contracts Supply Strategy:

Renewable Energy Contracts – CCA/MDU Options

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	7	52	1 Year
2007	Base (7 x 24)	8	51	1 Year
2008	Base (7 x 24)	10	52	1 Year
2009	Base (7 x 24)	11	52	1 Year
2010	Base (7 x 24)	13	52	1 Year
2011	Base (7 x 24)	15	53	1 Year
2012	Base (7 x 24)	17	54	1 Year
2013	Base (7 x 24)	18	54	1 Year
2014	Base (7 x 24)	20	54	1 Year
2015	Base (7 x 24)	23	54	1 Year
2016	Base (7 x 24)	25	53	1 Year
2017	Base (7 x 24)	28	53	1 Year
2018	Base (7 x 24)	29	55	3 Years
2021	Base (7 x 24)	30	58	3 Years

[44] Green tickets are negotiated traded instruments that satisfy the requirements associated with procuring renewable energy.

Renewable Energy Contracts – Greenfield Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	1	52	1 Year
2007	Base (7 x 24)	1	51	1 Year
2008	Base (7 x 24)	1	52	1 Year
2009	Base (7 x 24)	1	52	1 Year
2010	Base (7 x 24)	2	52	1 Year
2011	Base (7 x 24)	2	53	1 Year
2012	Base (7 x 24)	2	54	1 Year
2013	Base (7 x 24)	3	54	1 Year
2014	Base (7 x 24)	3	54	1 Year
2015	Base (7 x 24)	5	54	1 Year
2016	Base (7 x 24)	5	53	1 Year
2017	Base (7 x 24)	5	53	1 Year
2018	Base (7 x 24)	7	55	3 Years
2021	Base (7 x 24)	8	58	3 Years

d. Generation Ownership

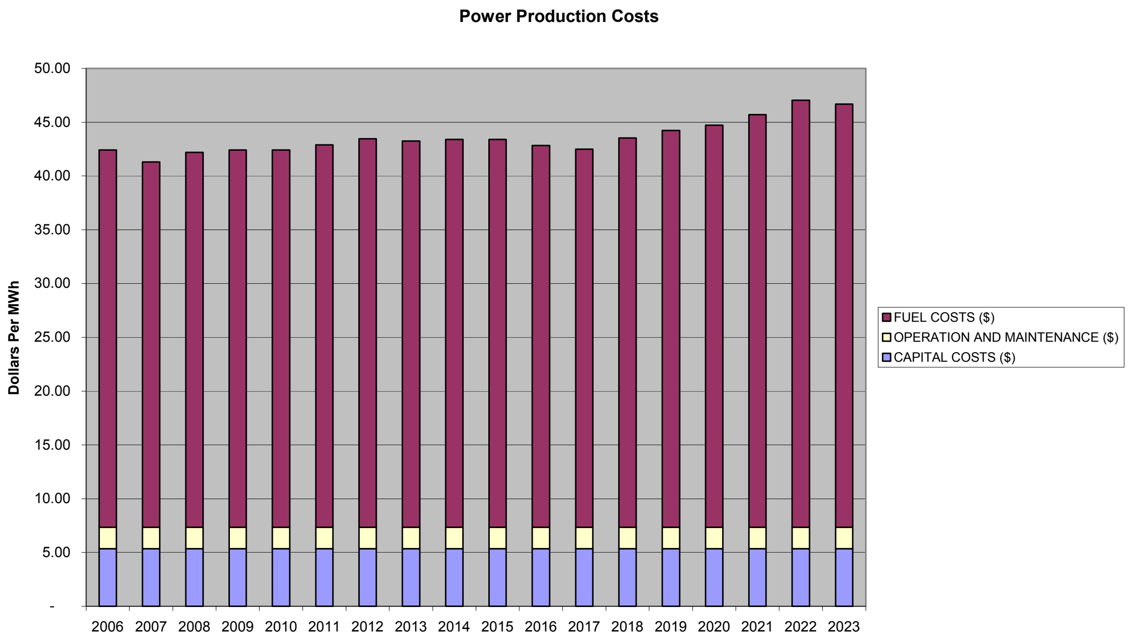
Generation options were modeled for the City using operating and cost parameters of a new combined cycle gas turbine operating as a base load plant. These parameters include the unit's heat rate, capacity cost, variable O&M costs, availability factor, hours of planned operation, and the year the resource becomes operational. Any excess production beyond what is needed to serve the City's load would be sold into the market. The price for excess capacity sales reflects a 25% discount relative to the prevailing peak or off-peak price to reflect the probability that excess sales will occur in the lowest priced hours of the on or off peak periods.

The following assumptions were used in the calculation of generation costs:

Capacity:	130 MW
Technology:	Combined Cycle Natural Gas Turbine
Year Online:	2006
Heat Rate:	7,000 BTU/KWh
Capacity Factor:	90%
Variable O&M:	$2 Per MWh
Excess Sales:	75% of Market Price

The electric production costs of City-owned generation are shown in the following chart:

Chart 15: Electricity Production Costs For City-Owned Combined Cycle Gas Turbine



The following charts show the composition of the two primary supply portfolios (Charts 16 and 18) and their respective average costs (Charts 17 and 19).

Chart 16: Loads and Resources On a Monthly Basis for 2006 – Generation Supply Strategy

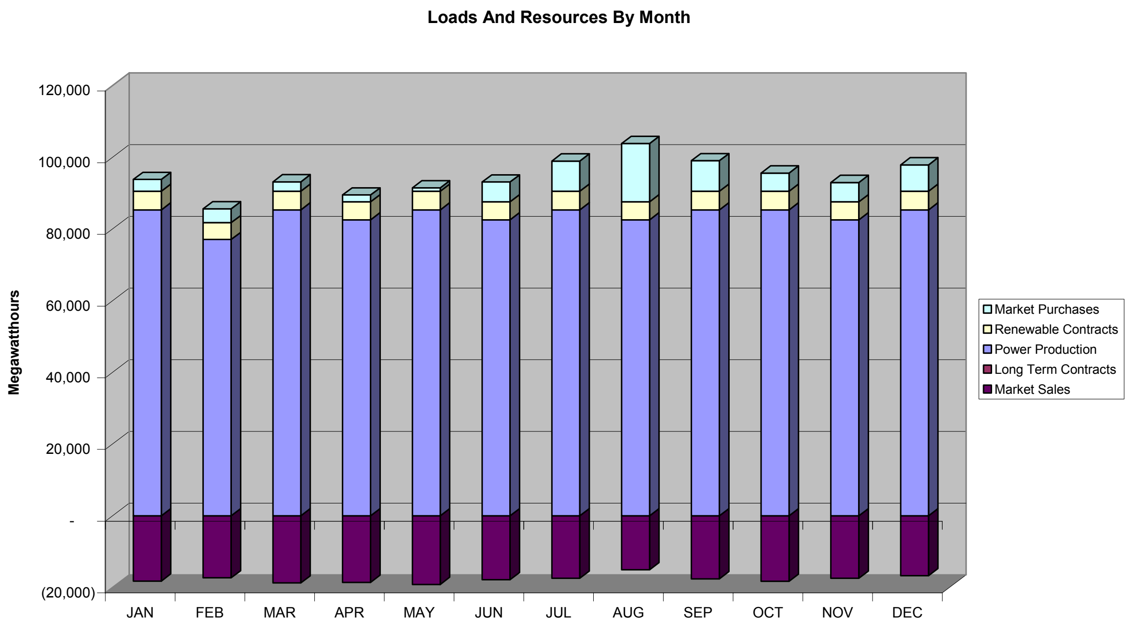


Chart 17: Average Supply Cost By Resource For 2006 – Generation Supply Strategy

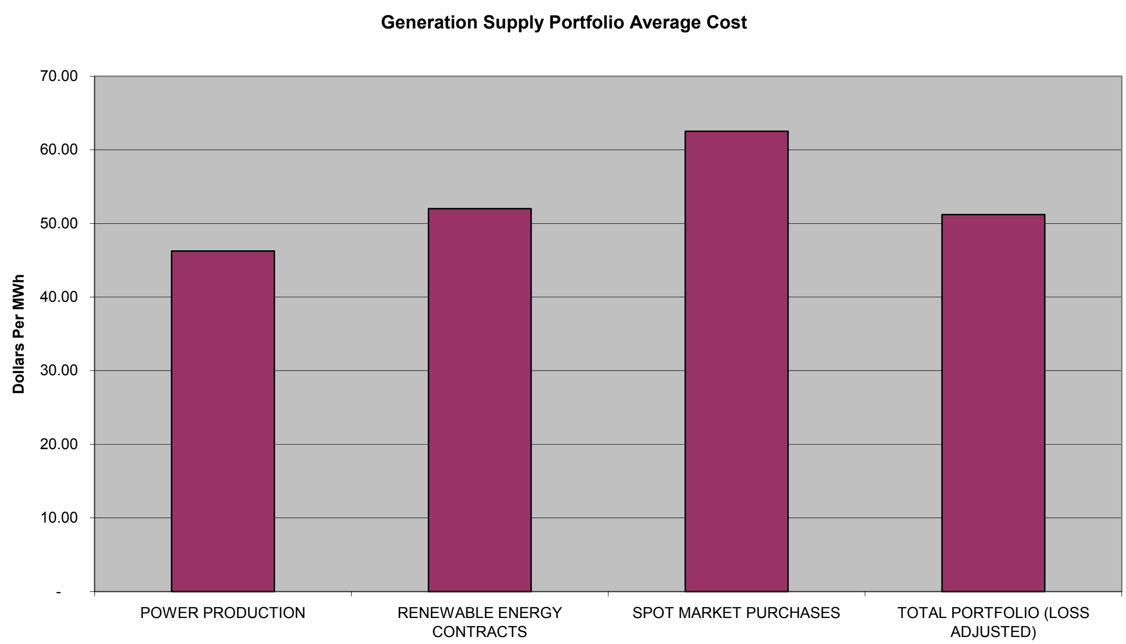


Chart 18: Loads And Resources On A Monthly Basis For 2006 – Contracts Supply Strategy

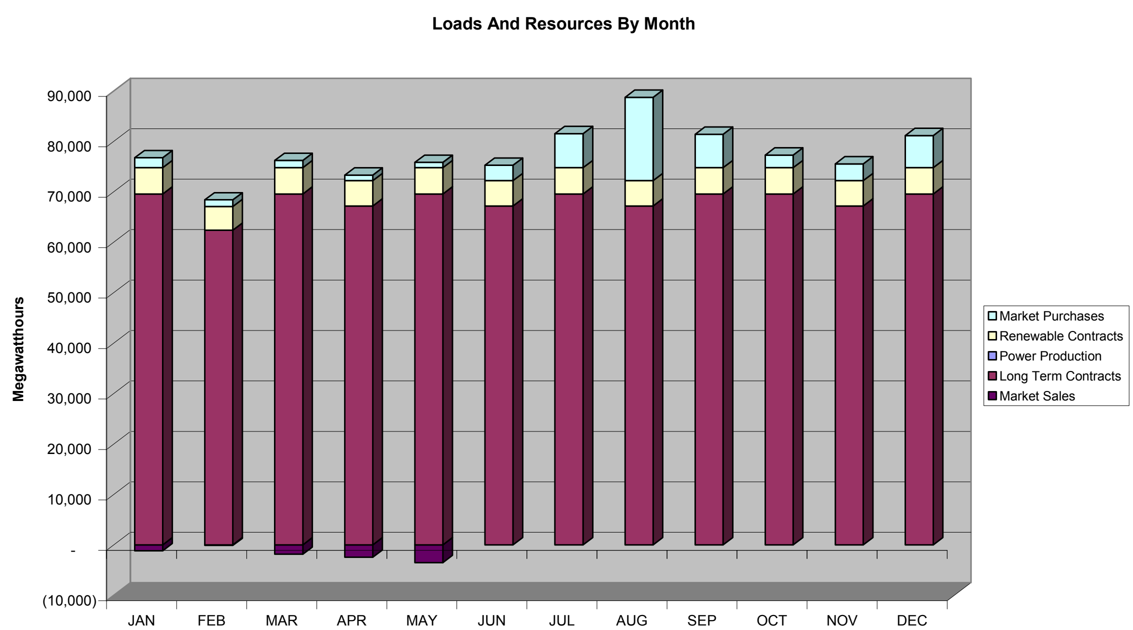
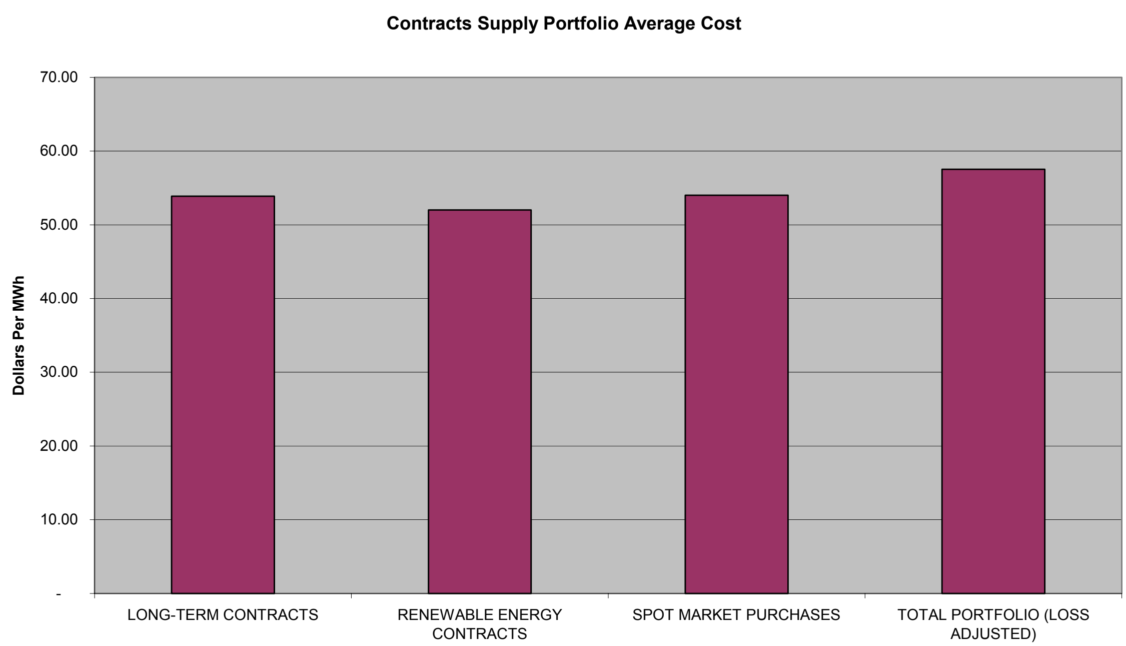


Chart 19: Average Supply Cost By Resource For 2006 – Contracts Supply Strategy



3. Portfolio Operations Costs

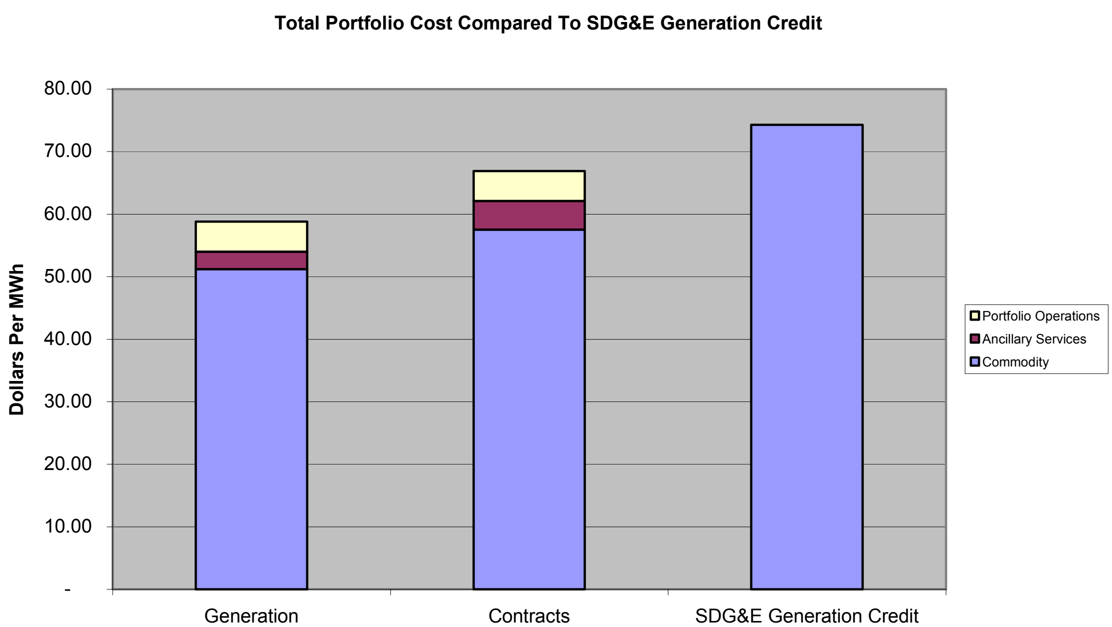
Portfolio operations costs are the costs associated with various activities related to procuring electricity for retail customers. Portfolio operations activities include load forecasting, procurement of electricity from wholesale electricity sellers, risk management and controls. Activities related to retail pricing (load research, cost of service, rate design) are also included in this cost category for purposes of the pro forma analysis.

Scheduling coordination costs are the costs associated with scheduling and settling electric supply transactions with the CAISO. The analysis assumes the City would become a CAISO certified Scheduling Coordinator, which would require acquisition of scheduling and settlements software and operation of a 24 x 7 scheduling desk.

Total costs of portfolio operations and scheduling coordination are modeled as a combination of fixed and variable costs. Fixed costs, largely associated with the minimum required personnel and computer systems, are estimated at $2,000,000 per year. Variable costs are estimated at $2.50 per MWh to account for increases in the size and sophistication of the portfolio operations corresponding with increases in the overall size of the utility.

Chart 20 below compares the total portfolio cost to the portion of the generation rate that would be credited by SDG&E for the initial year of operations in 2006. Total portfolio costs include the cost of the supply portfolio, ancillary services and portfolio operations and scheduling coordination costs. The total generation rate, net of the CPUC imposed exit fees, represents the avoidable portion of the generation rate. To achieve savings on the electric supply component of operations, the City must be able to acquire generation resources that are below these SDG&E costs. Both portfolios modeled for the City would be below SDG&E's generation costs.

Chart 20: Total Portfolio Costs Compared To Estimated SDG&E Generation Credit



C. Non-Bypassable Charges

1. CPUC Exit Fees

An important, but uncertain, element of MEU cost-of-service is the exit fees that the CPUC will impose on Municipal Departing Load or load served by a community choice aggregator. AB 117 and recent CPUC decisions require that exit fees, also known as cost responsibility surcharges, be imposed on existing and new customer load served by a community choice aggregator or new load served by a municipal utility in a Greenfield area, or existing load served by a newly formed municipal utility that has taken over the distribution system of the incumbent IOU. The categories of costs to be included in exit fees and the methodological approach to their calculation have largely been determined for direct access and Municipal Departing Load Customers. However, the actual per kWh charges have yet to be determined. On October 2, 2003, the CPUC initiated Rulemaking 03-10-003, which will, among other things, determine the exit fees that will be applicable to loads served by a CCA. Pursuant to a November 26, 2003 Administrative Law Judge Ruling in that proceeding, the issues regarding Community Choice Aggregation will be bifurcated into two phases, with the first phase addressing the cost elements, including the amount of a CRS and any other applicable charges.

The MEU Study Team has estimated the CPUC imposed exit fees based on the record in the direct access cost responsibility surcharge proceeding (R.02-01-011) using the DWR modeling scenario identified in CPUC Decision No. 03-07-030 as the most reasonable scenario (Scenario 14).

Exit fees for direct access customers are capped at $27 per MWh (2.7 cents per kWh). The cap was adopted by the CPUC to meet the objective of maintaining the viability of existing direct access contracts. The cap is not assumed to apply to CCA and future MEU activities, and the full, uncapped exit fees were included in the feasibility analysis. For SDG&E, the full cost exit fees are expected to be below the cap.

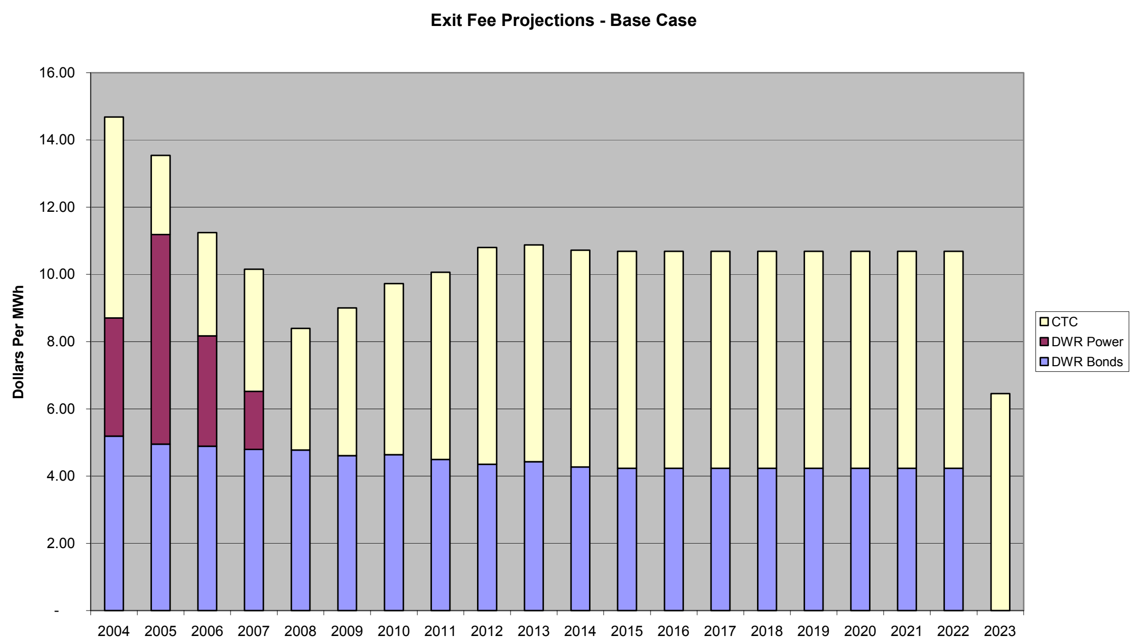
Exit fees have been incorporated into the analysis in each of the scenarios the MEU Study Team evaluated for the City. Exit fees are assumed to apply in all cases of CCA, MDU, and Greenfield development, consistent with the CPUC's proposed and final decisions in rulemaking proceeding R.02-01-011. Any changes to this assumption would impact the results of the analysis.

The MEU Study Team analysis assumes that the CPUC will impose exit fees on the City associated with the following costs:

- Uneconomic utility retained generation and power purchase contracts;
- DWR power purchase contracts; and
- DWR bond charges from DWR financing of past power purchases.

Chart 21 below depicts the annual exit fee projections on a Base Case basis:

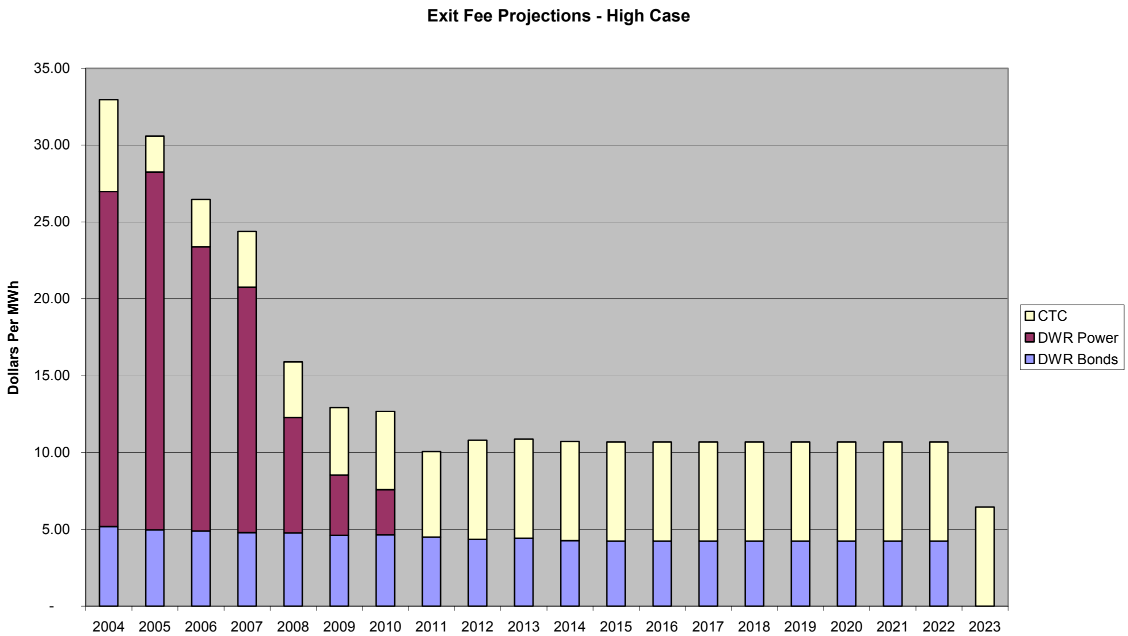
Chart 21: Annual Exit Fee Projections – Base Case



Consistent with the CPUC's exit fee methodology, the MEU Study Team independently calculated SDG&E's ongoing CTC and subtracted this component from the exit fees adopted in R.02-01-011 to allocate the total exit fees between DWR Power Charges and SDG&E's uneconomic URG. The MEU Study Team adjusted the $43 per MWh benchmark adopted by the CPUC for calculating the CTC to calibrate with projected wholesale electric market prices in future years.

Due to the uncertainty regarding the magnitude of exit fees, a high exit fee scenario should be considered. A reasonable basis for the high exit fee scenario is the original base case DWR modeling run (Scenario 24) in the capping phase of R.01-01-011. This scenario is based on gas price projections that are significantly lower than current and projected natural gas prices, which tends to reduce the electricity price assumed when the DWR contracts are sold into the market. In addition, this scenario included the assumption that the DWR contracts are sold into the market at a discount of 50% relative to prevailing market prices. The resulting annual exit fees for the high case scenario are shown in the following chart.

Chart 22: Annual Exit Fee Projections – High Case



2. Other Non-Bypassable Charges

Three additional non-bypassable charges must be accounted for in the MDU scenario. These are existing charges that were instituted at the time rates were unbundled to facilitate direct access in the late 1990's. Because these charges are not included in SDG&E's generation rates, it is not necessary to account for them in the comparison of CCA costs to SDG&E generation charges. The CCA customers would continue to pay these charges to SDG&E as part of the delivery services provided by the utility. These charges include the following:

- Public Purpose Programs
- Nuclear Decommissioning
- Fixed Transition Amount

a. Public Purpose Programs

Public Utilities Code 385 authorizes and requires local publicly owned electric utilities to collect through rates for local distribution service, revenue allocated to public benefits programs.

Public benefit programs referred to include the following:

i. Cost-effective demand-side management services to promote energy efficiency and energy conservation.
ii. New investment in renewable energy resources and technologies (subject to applicable statutes)
iii. Research, development and demonstration programs for public interest to advance science and technology that is not adequately provided by competitive and regulated markets.
iv. Service for low-income electricity customers, including, but not limited to, energy efficiency services, education, weatherization, and rate discounts.

The amount of the public benefits charge (on a percent of revenue basis) is the result of a complex formula set out in § 385, but must be "not less than the lowest expenditure level of the three largest electrical corporations in California." Currently, the public benefits charge percentage for local publicly owned utilities is 2.85%. The selection of public benefit programs to be funded by the charge is at the discretion of the local publicly owned utility, but must conform to the statutory requirements of § 385. Other legislation applicable to local publicly owned utilities involves consumer protection programs, and addresses such issues as low-income ratepayer assistance programs, weatherization programs, public reporting of revenues transferred to a city's general fund, and development of renewable resources. Limited only by the categories of "public benefits" set forth in the Code, municipal utilities have complete control over the funds collected, and can use 100% of those funds within the community. Public Goods Funds collected from local ratepayers by the investor owned utilities can be used on any number of programs approved the utility, and may never be expended within the community in which they are collected.

b. Nuclear Decommissioning Charges

These charges include costs related to the decommissioning of a nuclear power plant. These costs will be non-bypassable until such a time as the costs are fully recovered.

c. Fixed Transition Amount (FTA)

Sometimes referred to as Trust Transfer Amount (TTA), Residential and Small Commercial customers benefit from reduced rates through the issuance of the Rate Reduction Bonds. The Rate Reduction Bonds were issued to enable these customers to receive a discount on their bills of no less than 10% for the years 1998 through 2002. The proceeds of the Rate Reduction Bonds are used to provide, recover, finance, or refinance transition costs and to acquire transition property. Residential and small commercial customers would continue to pay fixed transition amounts after December 31 2001, until the bonds are paid in full by the financing entity.

D. CAISO Charges

1. Transmission

Under the MDU and Greenfield options, the City would take wholesale transmission service at the 115 KV voltage level and would be assessed CAISO charges for high and low voltage transmission service. Transmission costs are based on the currently effective CAISO transmission access charges applicable to the SDG&E area for high voltage and low voltage transmission service. The transmission charges were assumed to escalate at 1.3% per year. The first year transmission rates are shown below:

Charge Type	Rate
High Voltage (Regional) Transmission Charge	$2.33 Per MWh
Low Voltage (Local) Transmission Charge	$3.05 Per MWh

Internal generation would enable the MDU or Greenfield operation to avoid paying a portion of transmission access charges because the charges would be applied on the net load delivered over the transmission grid. In a CCA scenario, customers would continue to pay the retail transmission rates of SDG&E, which would not be impacted by the supply strategy pursued by the CCA.

2. Other CAISO Charges

Charges for Ancillary Services (spinning reserves, non-spinning reserves, regulation up, regulation down, and replacement reserves) imposed by the CAISO were modeled as a constant percentage of the prevailing wholesale market prices and applied to the CAISO's ancillary services requirements applicable to the City's load. City generation can be used to self-provide certain ancillary services, and any self-provided ancillary services are netted from the ancillary services purchased from the CAISO markets. Grid Management Charges, and other CAISO charges were modeled at current rate levels and escalated at 3% per year. These CAISO charges include:

Charge Type	Rate
GMC – Control Area Services	$0.62 Per MWh
GMC – Interzonal Scheduling	$0.39 Per MWh
GMC – Ancillary Services and Real Time Energy	$1.02 Per MWh
Reliability Services Costs	$2.34 Per MWh
Congestion Costs	$2.33 Per MWh
Grid Operations	$0.05 Per MWh
Unaccounted for energy	$0.76 Per MWh
Neutrality adjustments	$0.34 Per MWh
Deviations charges	Based on market prices

Internal generation would enable the MDU or Greenfield operation to avoid paying a portion of these charges through netting of the internal generation from gross loads. With the exception of Reliability Services Costs - which are not applicable to CCA - internal generation may also enable the CCA to avoid a portion of these CAISO charges through netting.

E. Distribution System Capital Costs

Acquisition or construction of distribution assets represents the main capital expenditures, outside the cost of generation development, associated with the MDU option or Greenfield development. If the City decides to operate a utility distribution system, it would be required to purchase SDG&E's distribution assets including land, property and rights. Included in the cost of the acquisition would be the expenses necessary to physically separate SDG&E from the distribution facilities purchased by the City (severance costs). An inventory and detailed assessment of the distribution facilities within the City was outside the scope of this study, and the MEU Study Team used average per customer distribution investment benchmarks to estimate the value of SDG&E facilities within the City.

1. Valuation Methods

In the MDU scenario, an acquisition price must be determined for the existing SDG&E distribution assets. In performing distribution system valuation there are several methodologies that may be applicable for the sale or purchase of facilities. These valuation methods are fully described and discussed in Appendix B, Regulatory and Legislative Issues, Section II.B at 30-33.

2. Analysis of Distribution System Capital Costs

The reasonable range of acquisition prices for SDG&E's distribution facilities would be bounded by original cost or book value on the lower end and RCN on the upper end. RCNLD would be within this range, and the MEU Study Team has used RCNLD to estimate distribution acquisition costs in the MDU scenario. New distribution facilities installed by SDG&E between 2003 and the 2006 MDU operation startup are valued at replacement cost, with no adjustment for depreciation. This figure was also used to calculate incremental distribution costs associated with customer growth of the MDU.

The MEU Study Team has estimated these costs on a per customer basis for the SDG&E system and applied the per customer figures to the number of customers in the city to estimate total book value and RCNLD of the distribution assets in the City.[45] Estimated regulatory and litigation costs are also included in the MDU and Greenfield scenarios.

[45] For street lighting customers, the projected customer numbers represent total numbers of lamps. In reality, each service account represents several lamps. To convert lamps to service accounts, the total projected annual kWh consumption for street lights was divided by 1,759 kWh, which is the typical annual consumption per street light service account.

Distribution system acquisition costs are estimated at approximately $170 million and total acquisition costs are estimated at $185 million as shown below.

Preexisting Facilities	Amount
RCNLD Per Customer	$2,021
Existing Customers	78,462
Existing Distribution Cost	$158,571,702

New Facilities[46]	Amount
RCN Per Customer	$3,000
New Customers	4,017
New Distribution Cost	$12,051,000
Total Distribution Cost	$170,622,702

Other costs related to the acquisition are estimated at $15 million as shown below:

Category	Amount
Regulatory/Litigation	$3 million
Inventory	$2 million
Severance	$10 million
Total Other Acquisition Costs	$15 million
Total Distribution Cost	$170 million
Other Acquisition Costs	$15 million
Total Acquisition Costs	$185 million

Annual debt service to support this investment would be approximately $20.2 million at an assumed taxable debt interest rate of 6.5%.

Greenfield Facilities

For Greenfield development, the $3,000 per customer replacement cost new figure was used to estimate construction costs. This figure was also used to calculate incremental distribution costs associated with customer growth of the Greenfield utility.

Distribution facilities costs are estimated at $12.1 million and total distribution infrastructure costs are estimated at $13.8 million as shown below.

[46] The cost for the acquisition of new facilities assumes that the City does not elect to pursue the Greenfield development option. If that option is pursued, these costs of $12.1 million would be subtracted from the distribution system acquisition costs to yield an acquisition cost of approximately $158.5 million.

New Facilities	Amount
RCN Per Customer	$3,000
Customers	4,017
Distribution Facilities Cost	$12,051,000

Distribution Facilities Cost	$12.1 million
Interconnection/WDAT	$0.7 million
Regulatory/Litigation	$0.5 million
Inventory	$0.5 million
Total Distribution Cost	$13.8 million

To determine the *book value* of the existing distribution system, it is only necessary to subtract its accumulated depreciation from its original cost. To further determine distribution system asset value requires consideration of the cost today to replace the system referred to as replacement cost new or RCN. Once the RCN is determined, it is then possible to determine the Replacement Cost New Less Depreciation.

The first step that the MEU Study Team took to determining the potential value of the distribution system within the City was to look at SDG&E's latest FERC Form 1 (2002) to determine the original cost of all of SDG&E's distribution system. This cost is then compared to the total number of SDG&E's customers to arrive at a cost per customer.

SDG&E's Original Cost of the Distribution Plant	-	$2,700,975,584
SDG&E total customers	-	1,255,268
SDG&E Original Cost per Customer	-	$2,151.71

The next step was to arrive at the current or booked value of SDG&E's distribution system that is the original cost less accumulated depreciation. Again SDG&E's 2002 FERC Form 1 was the reference point.

SDG&E Net Book Value for Distribution Plant	-	$1,542,105,376
SDG&E Total Customers	-	1,255,268
SDG&E Book Value per Customer	-	$1,228.51

With these two reference points it is possible to use the Handy-Whitman Index to determine the Replacement Cost New Less Depreciation (RCNLD) for SDG&E's distribution system. The Handy Whitman Index of Public Utility Costs is a widely used publication used to trend original cost valuations to present day reconstruction costs. Utilizing the Handy Whitman Index requires knowledge of the original cost and the time of the original cost investment. Typical depreciation for distribution plant is 30 to 40 years. The original cost of SDG&E's distribution system and its current book value indicates the system is approximately 43 percent depreciated.

If the average depreciation period is 30 years the average age of the system is approximately 13 years. If the average depreciation period is 40 years, the average age of the SDG&E distribution system is 17 years. Hence, the Handy Whitman Index[47] for 1989 and 1985 (13 and 17 years ago) were utilized to determine the potential replacement cost of the SDG&E distribution system.

Original Cost per Customer	-	\$2,151.71
2002 Handy Whitman Index	-	366
1989 HWI	-	277
1985 HWI	-	250
Cost of Replacement per Customer (1989 HWI)	-	\$2,843.06
Cost of Replacement per Customer (1985 HWI)	-	\$3,150.11

Based upon these two ranges of potential replacement costs, the MEU Study team used a replacement cost of \$3,000 per customer. Therefore, the RCNLD for the total SDG&E system is as follows:

Replacement Cost New per Customer	-	\$3,000
Number of Customers	-	1,255,268
Total Replacement Cost	-	\$3,765,804,000
Accumulated Depreciation	-	\$1,228,828,000
RCNLD	-	\$2,536,975,505
RCNLD Per Customer	-	\$2,021

F. Distribution System Operations and Maintenance Costs

The MEU Study Team used the results of a nationwide benchmarking study of municipal electric utilities to estimate distribution O&M costs for the City. The study groups municipal electric utilities by size into five strata and reports average per customer O&M costs within each strata for distribution O&M, customer service expenses, and administrative and general expenses. The average total annual distribution O&M costs reported by participants in the study range from \$246 to \$594 per customer, reflecting a wide range of urban and rural municipal utilities of various sizes and population densities.

The MEU Study Team has also used a targeted set of case studies of California municipal electric utilities to obtain O&M estimates that would be more reflective of the costs expected for the City municipal electric utility. Data are available for years 1998-2001, and the average total annual distribution O&M costs range from \$231 to \$380 per customer. For this analysis, the four-year average per customer O&M costs of California municipal utilities of similar size as Chula Vista was used to predict the cost for distribution operations. Four municipal utilities with between 50,000 and 90,000 customers were selected. These were Burbank, Glendale, Pasadena, and the Turlock Irrigation District.

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[47] The MEU Study Team used the Handy Whitman Index for the Pacific Region in this analysis.

Based on this analysis, the average annual O&M cost estimated for the City is $270 per customer.

By comparison, the MEU Study Team has calculated the average distribution O&M costs for SDG&E, using 2002 FERC Form 1 data, of $198 per customer.

Category	Amount
Distribution O&M	$76,310,456
Customer Service O&M	$78,025,205
Allocation of A&G	$94,739,319
Total Distribution O&M	$249,074,980
Total Customers	1,255,268
Distribution O&M Per Customer	$198

The lower figure for SDG&E reflects economies of scale in distribution operations that are not available to smaller distribution systems. The higher per capita O&M costs typical of smaller utilities are offset to a degree by the capital financing and tax advantages of municipal electric utilities.

G. Utility Financing

The City would have strong financing advantages relative to SDG&E due to its lower cost of capital arising from access to low cost debt and exemption from federal and state income taxes. The MEU Study Team's analytical model enables a variety of financing assumptions for the capital requirements associated with distribution or generation investments. Configurable assumptions include the cost of debt, the length of the debt term, the capital structure or debt ratio, and the debt coverage ratio.

Tax-exempt financing is not applicable to the acquisition of existing distribution assets and was not used in the analysis. Tax-exempt financing was only assumed to be used for all new distribution and generation facility development. The following financing assumptions were used in the analysis:

Capital Expenditure	Tax Status	Annual Rate	Term
Generation Development	Exempt	5.5%	30 Years
Distribution Acquisition	Taxable	6.5%	30 Years
Capital Additions	Exempt	5.5%	30 Years

H. Additional Cost Considerations

1. Franchise Fee Impacts

Acquisition of SDG&E's distribution facilities negatively impacts the

City's franchise fees revenues and is assumed to trigger a requirement for in lieu payments of lost county property taxes. Lost franchise fee payments are included in the financial analysis as a cost of the municipal electric utility operations. The $881,077 in franchise fees paid by SDG&E to the City in 2002 was escalated at an annual rate of 2.5% throughout the study period.

2. In-Lieu Property Tax Payments

In-lieu payments to San Diego County for lost property tax revenues were estimated using the County of San Diego's tax rate applicable to Chula Vista (1.0732%), and then applied to the estimated value of SDG&E's distribution assets in the City. Foregone property taxes are estimated at $1.8 million per year.

Foregone property taxes and in-lieu payments are accounted for as additional costs of operating the municipal electric utility in the financial pro-forma analysis. The economics of the MDU must overcome these additional costs in order to be viable, and the savings shown in the pro forma results have already accounted for these opportunity costs.

I. Pro Forma Analyses

The following attachments (pp. 90-98) are the financial pro forma analyses developed by the MEU Study Team for the evaluated MEU options:[48]

Pro Forma	Structure Option	Supply Strategy	Areas
1	CCA	Generation	Existing and Developing
2	CCA	Contracts	Existing and Developing
3	Greenfield	Contracts	Developing
4	CCA and Greenfield	Generation	Developing
5	CCA and Greenfield	Generation	Existing
6	CCA and Greenfield	Contracts	Developing
7	CCA and Greenfield	Contracts	Existing
8	Municipal Distribution Utility	Generation	Existing and Developing
9	Municipal Distribution Utility	Contracts	Existing and Developing

The financial pro forma of the Natural Gas Utility option discussed in Section IV.H of the Report is also attached at 99.

48 These pro formas are in a separate Excel file in the electronic version of the Report.

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME

MDU OPTION - CONTRACTS

CATEGORY	NPV	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		74,440	76,940	79,022	81,105	83,187	83,770	84,353	84,935	85,518	86,101	86,684	87,267	87,850	88,432	89,015	89,180	89,345	89,510
(B) SMALL COMMERCIAL (A)		3,450	3,495	3,540	3,605	3,689	3,710	3,731	3,753	3,820	3,991	4,024	4,056	4,089	4,122	4,154	4,193	4,232	4,272
(C) MEDIUM COMMERCIAL (AL-TOU)		413	418	423	442	491	506	522	537	561	606	621	635	649	664	683	691	700	708
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		14	15	15	15	15	16	16	16	16	19	20	20	20	20	21	22	22	22
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		4,162	4,267	4,375	4,485	4,172	4,277	4,385	4,496	4,609	4,649	4,689	4,730	4,770	4,812	4,851	4,891	4,931	9,956
SUBTOTAL - CUSTOMER ACCOUNTS		82,479	85,134	87,375	89,652	91,554	92,279	93,006	93,737	94,525	95,367	96,037	96,708	97,379	98,051	98,725	98,977	99,230	104,469
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		373,441,677	391,414,163	407,663,619	424,292,848	441,309,320	450,654,032	460,174,341	469,873,338	479,754,166	489,820,022	500,074,156	510,519,875	521,160,540	531,999,567	543,040,434	551,486,365	560,062,938	568,772,167
(B) SMALL COMMERCIAL (A)		63,115,857	63,935,426	64,763,744	65,959,906	67,482,251	67,870,336	68,260,307	68,652,173	69,891,668	73,021,464	73,612,809	74,208,888	74,809,742	75,415,411	76,001,183	76,711,393	77,428,899	78,153,786
(C) MEDIUM COMMERCIAL (AL-TOU)		255,962,359	259,042,244	262,152,252	274,004,181	304,124,450	313,764,856	323,411,752	333,065,175	347,799,493	376,020,275	384,891,687	393,779,394	402,683,539	411,604,263	423,370,462	428,564,773	433,830,939	439,170,047
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		162,345,060	164,474,940	166,627,065	169,878,669	174,290,700	175,299,094	176,312,282	177,330,290	185,930,574	219,587,916	221,111,166	222,646,450	224,193,873	229,482,144	242,178,517	244,816,376	247,486,932	250,190,642
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		7,321,167	7,505,737	7,694,960	7,888,953	7,338,790	7,523,804	7,713,482	7,907,942	8,107,305	8,177,335	8,247,970	8,319,214	8,391,075	8,463,556	8,533,055	8,603,126	8,673,771	8,744,997
SUBTOTAL - LOAD REQUIREMENTS		862,186,120	886,372,509	908,901,639	942,024,556	994,545,510	1,015,112,122	1,035,872,164	1,056,828,918	1,091,483,206	1,166,627,011	1,187,937,787	1,209,473,823	1,231,238,769	1,256,964,942	1,293,123,651	1,310,182,032	1,327,483,480	1,345,031,639
III. ESTIMATED SDG&E RATES ($/KWH):																			
RESIDENTIAL		$0.157	$0.155	$0.144	$0.146	$0.147	$0.141	$0.143	$0.146	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.167	$0.171	$0.171	$0.166
SMALL COMMERCIAL (A)		$0.179	$0.177	$0.165	$0.167	$0.169	$0.162	$0.165	$0.168	$0.171	$0.174	$0.178	$0.181	$0.185	$0.189	$0.192	$0.196	$0.196	$0.192
MEDIUM COMMERCIAL (AL-TOU)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
AGRICULTURAL		$0.167	$0.165	$0.164	$0.165	$0.167	$0.160	$0.163	$0.166	$0.169	$0.172	$0.175	$0.179	$0.182	$0.185	$0.189	$0.192	$0.192	$0.188
STREET LIGHTING & TRAFFIC CONTROL		$0.111	$0.109	$0.108	$0.109	$0.110	$0.106	$0.108	$0.110	$0.112	$0.114	$0.116	$0.118	$0.120	$0.122	$0.124	$0.127	$0.127	$0.123
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
RESIDENTIAL		58,552,103	60,641,315	58,685,254	61,742,140	64,848,704	63,417,095	65,927,499	68,674,967	71,422,135	74,341,024	77,395,366	80,573,445	83,880,268	87,321,043	90,901,189	94,148,286	95,612,456	94,690,267
SMALL COMMERCIAL (A)		11,323,342	11,334,520	10,712,202	11,030,047	11,395,131	10,976,784	11,240,797	11,532,507	11,960,456	12,739,697	13,096,215	13,463,019	13,840,417	14,228,726	14,623,512	15,053,142	15,193,939	15,005,168
MEDIUM COMMERCIAL (AL-TOU)		36,537,697	36,537,416	36,598,804	38,637,960	43,280,178	42,875,773	44,936,486	47,153,644	50,091,865	55,144,729	57,492,156	59,912,754	62,408,718	64,982,308	68,090,801	70,219,164	71,082,011	70,096,727
LARGE INDUSTRIAL (AL-TOU, + 500 KW)		23,174,167	23,198,877	23,262,632	23,954,982	24,803,440	23,954,513	24,497,732	25,105,505	26,778,674	32,203,360	33,027,883	33,875,216	34,746,025	36,229,652	38,949,645	40,112,493	40,550,056	39,933,382
AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
STREET LIGHTING & TRAFFIC CONTROL		810,702	821,190	833,354	862,569	809,770	797,235	830,677	867,723	904,553	928,804	954,044	980,014	1,006,738	1,034,237	1,062,088	1,090,737	1,099,694	1,071,685
TOTAL REVENUE REQUIREMENT		$130,398,011	$132,533,318	$130,092,246	$136,227,699	$145,137,222	$142,021,400	$147,433,192	$153,334,345	$161,157,683	$175,357,615	$181,965,664	$188,804,449	$195,882,166	$203,795,967	$213,627,234	$220,623,822	$223,538,155	$220,797,229
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$2,802,774	$3,423,630	$3,847,307	$5,183,837	$7,270,636	$7,672,202	$8,107,973	$8,828,611	$9,976,579	$12,969,913	$665,704	$691,528	$808,689	$1,172,401	$1,859,978	$2,173,370	$2,791,605	$3,288,316
(ii) CONTRACT PURCHASES		$47,094,240	$47,479,680	$48,460,800	$48,916,320	$49,827,360	$52,506,600	$53,584,080	$54,057,120	$55,003,200	$56,422,320	$76,053,200	$77,446,040	$78,418,400	$78,418,400	$78,418,400	$84,852,600	$84,852,600	$84,852,600
(iii) POWER PRODUCTION		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(iv) DWR POWER		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) TRANSMISSION AND SCHEDULING		$9,296,043	$9,543,029	$9,795,931	$10,138,502	$10,669,586	$10,930,912	$11,198,368	$11,472,112	$11,874,412	$12,653,511	$13,710,661	$14,048,054	$14,284,510	$14,500,596	$14,776,354	$15,028,840	$15,251,434	$15,475,413
(vi) DISTRIBUTION		$18,879,281	$19,674,243	$20,345,081	$21,027,004	$21,596,441	$21,813,493	$22,031,372	$22,250,100	$22,486,191	$22,738,384	$22,938,933	$23,139,673	$23,340,603	$23,541,825	$23,743,785	$23,819,330	$23,895,128	$25,463,726
(vii) CALIFORNIA ISO COSTS		$4,338,004	$4,565,082	$4,812,332	$5,120,625	$5,560,580	$5,841,558	$6,135,724	$6,440,006	$6,844,423	$7,527,682	$8,503,719	$8,915,144	$9,261,415	$9,594,827	$9,979,514	$10,374,284	$10,755,169	$11,138,146
(viii) ANCILLARY SERVICES & CAPACITY RESERVES		$1,923,853	$1,917,335	$2,016,453	$2,102,070	$2,219,529	$2,295,830	$2,378,226	$2,412,909	$2,501,353	$2,673,255	$2,681,627	$2,704,521	$2,832,045	$2,944,842	$3,068,063	$3,186,789	$3,336,472	$3,352,051
SUBTOTAL - POWER SUPPLY AND DELIVERY		$84,334,195	$86,602,998	$89,277,904	$92,488,359	$97,144,132	$101,060,595	$103,435,743	$105,460,858	$108,686,158	$114,985,065	$124,553,844	$126,944,959	$128,945,662	$130,172,892	$131,846,093	$139,435,213	$140,882,408	$143,570,252
(B) UTILITY OPERATIONS:																			
(i) DISTRIBUTION O&M		$10,119,642	$10,706,512	$11,262,967	$11,845,443	$12,399,129	$12,809,731	$13,233,507	$13,670,879	$14,130,518	$14,612,833	$15,083,345	$15,568,352	$16,068,287	$16,583,654	$17,115,173	$17,587,884	$18,073,687	$19,503,524
(ii) CUSTOMER SERVICE		$3,328,488	$3,521,517	$3,704,543	$3,896,127	$4,078,242	$4,213,295	$4,352,680	$4,496,538	$4,647,719	$4,806,359	$4,961,117	$5,120,643	$5,285,078	$5,454,589	$5,629,413	$5,784,894	$5,944,681	$6,414,974
(iii) ADMINSTRATIVE & GENERAL		$11,131,227	$11,776,762	$12,388,842	$13,029,544	$13,638,577	$14,090,224	$14,556,362	$15,037,455	$15,543,040	$16,073,569	$16,591,115	$17,124,604	$17,674,514	$18,241,398	$18,826,049	$19,346,013	$19,880,379	$21,453,146
SUBTOTAL - UTILITY OPERATIONS		$24,579,357	$26,004,792	$27,356,351	$28,771,115	$30,115,948	$31,113,250	$32,142,550	$33,204,873	$34,321,277	$35,492,761	$36,635,577	$37,813,598	$39,027,879	$40,279,641	$41,570,635	$42,718,791	$43,898,747	$47,371,644
(C) PUBLIC PURPOSE PROGRAMS		$5,931,552	$6,083,382	$6,006,928	$6,268,041	$6,611,415	$6,871,007	$7,080,660	$7,242,177	$7,459,316	$7,854,031	$8,370,238	$8,551,014	$8,715,299	$8,847,398	$9,008,579	$9,429,900	$9,564,313	$9,597,264
(D) FRANCHISE FEES		$972,544	$996,858	$1,021,779	$1,047,324	$1,073,507	$1,100,344	$1,127,853	$1,156,049	$1,184,951	$1,214,574	$1,244,939	$1,276,062	$1,307,964	$1,340,663	$1,374,179	$1,408,534	$1,443,747	$1,479,841
(E) PROPERTY TAXES		$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131
(F) NON-BYPASSABLE CHARGES		$7,045,213	$5,782,910	$4,337,924	$4,344,751	$4,609,667	$4,562,411	$4,509,458	$4,679,603	$4,660,510	$4,941,188	$5,031,449	$5,122,663	$5,214,848	$5,323,809	$5,476,958	$5,549,208	$5,622,487	$0
(G) OTHER "PASS-THROUGH" COSTS		$7,484,564	$8,259,857	$4,026,222	$4,926,163	$5,942,803	$6,574,605	$7,657,856	$7,809,797	$8,079,882	$8,700,279	$8,855,013	$9,011,154	$9,168,722	$9,359,669	$9,639,389	$9,762,876	$9,888,094	$10,015,067
TOTAL - OPERATING EXPENSES		$132,178,554	$135,561,927	$133,858,239	$139,676,883	$147,328,603	$153,113,342	$157,785,250	$161,384,487	$166,223,225	$175,019,028	$186,522,191	$190,550,581	$194,211,504	$197,155,202	$200,746,965	$210,135,652	$213,130,927	$213,865,199
(H) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$299,001	$145,396	$96,855	$10,577	$0	$0	$0	$0	$0	$0	$4,196,997	$4,235,255	$3,815,499	$3,014,152	$1,946,781	$1,763,693	$1,413,627	$1,026,658
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$299,001	$145,396	$96,855	$10,577	$0	$0	$0	$0	$0	$0	$4,196,997	$4,235,255	$3,815,499	$3,014,152	$1,946,781	$1,763,693	$1,413,627	$1,026,658
TOTAL EXPENSES NET OF MARKET REVENUES		$131,879,553	$135,416,531	$133,761,384	$139,666,306	$147,328,603	$153,113,342	$157,785,250	$161,384,487	$166,223,225	$175,019,028	$182,325,194	$186,315,326	$190,396,005	$194,141,050	$198,800,183	$208,371,959	$211,717,300	$212,838,540
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$130,398,011	$132,533,318	$130,092,246	$136,227,699	$145,137,222	$142,021,400	$147,433,192	$153,334,345	$161,157,683	$175,357,615	$181,965,664	$188,804,449	$195,882,166	$203,795,967	$213,627,234	$220,623,822	$223,538,155	$220,797,229
(B) CHULA VISTA REVENUE REQUIREMENT		$131,879,553	$135,416,531	$133,761,384	$139,666,306	$147,328,603	$153,113,342	$157,785,250	$161,384,487	$166,223,225	$175,019,028	$182,325,194	$186,315,326	$190,396,005	$194,141,050	$198,800,183	$208,371,959	$211,717,300	$212,838,540
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	($11,597,761)	($1,481,542)	($2,883,213)	($3,669,139)	($3,438,607)	($2,191,381)	($11,091,942)	($10,352,059)	($8,050,142)	($5,065,542)	$338,587	($359,530)	$2,489,123	$5,486,161	$9,654,917	$14,827,050	$12,251,862	$11,820,856	$7,958,689
(D) BENEFITS	-1.0%	-1.1%	-2.2%	-2.8%	-2.5%	-1.5%	-7.8%	-7.0%	-5.3%	-3.1%	0.2%	-0.2%	1.3%	2.8%	4.7%	6.9%	5.6%	5.3%	3.6%

NPV 2006-2023	($11,597,761)	($1,481,542)	($2,883,213)	($3,669,139)	($3,438,607)	($2,191,381)	($11,091,942)	($10,352,059)	($8,050,142)	($5,065,542)	$338,587	($359,530)	$2,489,123	$5,486,161	$9,654,917	$14,827,050	$12,251,862	$11,820,856	$7,958,689
NPV 2006-2014	($25,157,033)	($1,481,542)	($2,883,213)	($3,669,139)	($3,438,607)	($2,191,381)	($11,091,942)	($10,352,059)	($8,050,142)	($5,065,542)									
NPV 2015-2023	$13,559,272	0	0	0	0	0	0	0	0	0	$338,587	($359,530)	$2,489,123	$5,486,161	$9,654,917	$14,827,050	$12,251,862	$11,820,856	$7,958,689

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME
MDU OPTION - GENERATION

CATEGORY	NPV	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		74,440	76,940	79,022	81,105	83,187	83,770	84,353	84,935	85,518	86,101	86,684	87,267	87,850	88,432	89,015	89,180	89,345	89,510
(B) SMALL COMMERCIAL (A)		3,450	3,495	3,540	3,605	3,689	3,710	3,731	3,753	3,820	3,991	4,024	4,056	4,089	4,122	4,154	4,193	4,232	4,272
(C) MEDIUM COMMERCIAL (AL-TOU)		413	418	423	442	491	506	522	537	561	606	621	635	649	664	683	691	700	708
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		14	15	15	15	15	16	16	16	16	19	20	20	20	20	21	22	22	22
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		4,162	4,267	4,375	4,485	4,172	4,277	4,385	4,496	4,609	4,649	4,689	4,730	4,770	4,812	4,851	4,891	4,931	9,956
SUBTOTAL - CUSTOMER ACCOUNTS		82,479	85,134	87,375	89,652	91,554	92,279	93,006	93,737	94,525	95,367	96,037	96,708	97,379	98,051	98,725	98,977	99,230	104,469
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		373,441,677	391,414,163	407,663,619	424,292,848	441,309,320	450,654,032	460,174,341	469,873,338	479,754,166	489,820,022	500,074,156	510,519,875	521,160,540	531,999,567	543,040,434	551,486,365	560,062,938	568,772,167
(B) SMALL COMMERCIAL (A)		63,115,857	63,935,426	64,763,744	65,959,906	67,482,251	67,870,336	68,260,307	68,652,173	69,891,668	73,021,464	73,612,809	74,208,888	74,809,742	75,415,411	76,001,183	76,711,393	77,428,899	78,153,786
(C) MEDIUM COMMERCIAL (AL-TOU)		255,962,359	259,042,244	262,152,252	274,004,181	304,124,450	313,764,856	323,411,752	333,065,175	347,799,493	376,020,275	384,891,687	393,779,394	402,683,539	411,604,263	423,370,462	428,564,773	433,830,939	439,170,047
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		162,345,060	164,474,940	166,627,065	169,878,669	174,290,700	175,299,094	176,312,282	177,330,290	185,930,574	219,587,916	221,111,166	222,646,450	224,193,873	229,482,144	242,178,517	244,816,376	247,486,932	250,190,642
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		7,321,167	7,505,737	7,694,960	7,888,953	7,338,790	7,523,804	7,713,482	7,907,942	8,107,305	8,177,335	8,247,970	8,319,214	8,391,075	8,463,556	8,533,055	8,603,126	8,673,771	8,744,997
SUBTOTAL - LOAD REQUIREMENTS		862,186,120	886,372,509	908,901,639	942,024,556	994,545,510	1,015,112,122	1,035,872,164	1,056,828,918	1,091,483,206	1,166,627,011	1,187,937,787	1,209,473,823	1,231,238,769	1,256,964,942	1,293,123,651	1,310,182,032	1,327,483,480	1,345,031,639
III. ESTIMATED SDG&E RATES ($/KWH):																			
RESIDENTIAL		$0.157	$0.155	$0.144	$0.146	$0.147	$0.141	$0.143	$0.146	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.167	$0.171	$0.171	$0.166
SMALL COMMERCIAL (A)		$0.179	$0.177	$0.165	$0.167	$0.169	$0.162	$0.165	$0.168	$0.171	$0.174	$0.178	$0.181	$0.185	$0.189	$0.192	$0.196	$0.196	$0.192
MEDIUM COMMERCIAL (AL-TOU)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
AGRICULTURAL		$0.167	$0.165	$0.164	$0.165	$0.167	$0.160	$0.163	$0.166	$0.169	$0.172	$0.175	$0.179	$0.182	$0.185	$0.189	$0.192	$0.192	$0.188
STREET LIGHTING & TRAFFIC CONTROL		$0.111	$0.109	$0.108	$0.109	$0.110	$0.106	$0.108	$0.110	$0.112	$0.114	$0.116	$0.118	$0.120	$0.122	$0.124	$0.127	$0.127	$0.123
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
RESIDENTIAL		58,552,103	60,641,315	58,685,254	61,742,140	64,848,704	63,417,095	65,927,499	68,674,967	71,422,135	74,341,024	77,395,366	80,573,445	83,880,268	87,321,043	90,901,189	94,148,286	95,612,456	94,690,267
SMALL COMMERCIAL (A)		11,323,342	11,334,520	10,712,202	11,030,047	11,395,131	10,976,784	11,240,797	11,532,507	11,960,456	12,739,697	13,096,215	13,463,019	13,840,417	14,228,726	14,623,512	15,053,142	15,193,939	15,005,168
MEDIUM COMMERCIAL (AL-TOU)		36,537,697	36,537,416	36,598,804	38,637,960	43,280,178	42,875,773	44,936,486	47,153,644	50,091,865	55,144,729	57,492,156	59,912,754	62,408,718	64,982,308	68,090,801	70,219,164	71,082,011	70,096,727
LARGE INDUSTRIAL (AL-TOU, + 500 KW)		23,174,167	23,198,877	23,262,632	23,954,982	24,803,440	23,954,513	24,497,732	25,105,505	26,778,674	32,203,360	33,027,883	33,875,216	34,746,025	36,229,652	38,949,645	40,112,493	40,550,056	39,933,382
AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
STREET LIGHTING & TRAFFIC CONTROL		810,702	821,190	833,354	862,569	809,770	797,235	830,677	867,723	904,553	928,804	954,044	980,014	1,006,738	1,034,237	1,062,088	1,090,737	1,099,694	1,071,685
TOTAL REVENUE REQUIREMENT		$130,398,011	$132,533,318	$130,092,246	$136,227,699	$145,137,222	$142,021,400	$147,433,192	$153,334,345	$161,157,683	$175,357,615	$181,965,664	$188,804,449	$195,882,166	$203,795,967	$213,627,234	$220,623,822	$223,538,155	$220,797,229
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$4,317,306	$4,975,119	$5,551,166	$6,807,146	$8,651,115	$9,134,242	$9,653,946	$10,282,916	$11,346,958	$13,953,670	$14,148,969	$14,136,942	$15,269,679	$16,780,898	$18,735,293	$19,739,659	$21,284,026	$21,756,753
(ii) CONTRACT PURCHASES		$3,188,640	$3,574,080	$4,555,200	$5,010,720	$5,921,760	$6,964,200	$8,041,680	$8,514,720	$9,460,800	$10,879,920	$11,607,000	$12,999,840	$13,972,200	$13,972,200	$13,972,200	$15,242,400	$15,242,400	$15,242,400
(iii) POWER PRODUCTION		$42,600,729	$41,475,777	$42,389,801	$42,600,729	$42,600,729	$43,092,896	$43,655,372	$43,444,443	$43,585,062	$43,585,062	$43,022,586	$42,671,039	$43,725,681	$44,428,776	$44,920,943	$45,905,276	$47,241,157	$46,889,609
(iv) DWR POWER		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) TRANSMISSION AND SCHEDULING		$4,874,914	$5,072,951	$5,283,643	$5,552,022	$5,986,730	$6,197,236	$6,413,012	$6,611,917	$6,937,456	$7,591,513	$7,832,450	$8,102,973	$8,332,870	$8,572,862	$8,897,189	$9,102,959	$9,289,248	$9,454,539
(vi) DISTRIBUTION		$18,879,281	$19,674,243	$20,345,081	$21,027,004	$21,596,441	$21,813,493	$22,031,372	$22,250,100	$22,486,191	$22,738,384	$22,938,933	$23,139,673	$23,340,603	$23,541,825	$23,743,785	$23,819,330	$23,895,128	$25,463,726
(vii) CALIFORNIA ISO COSTS		$1,221,888	$1,369,651	$1,534,230	$1,736,811	$2,052,643	$2,239,139	$2,435,778	$2,624,669	$2,908,237	$3,429,394	$3,678,139	$3,959,458	$4,218,161	$4,489,766	$4,834,066	$5,102,735	$5,362,942	$5,608,065
(viii) ANCILLARY SERVICES & CAPACITY RESERVES		$1,501,179	$1,519,289	$1,619,387	$1,719,266	$1,863,002	$1,944,960	$2,032,745	$2,080,079	$2,185,047	$2,395,405	$2,418,693	$2,454,861	$2,586,458	$2,708,185	$2,847,559	$2,970,020	$3,122,211	$3,149,428
SUBTOTAL - POWER SUPPLY AND DELIVERY		$76,583,936	$77,661,109	$81,278,508	$84,453,698	$88,672,420	$91,386,164	$94,263,905	$95,808,844	$98,909,752	$104,573,348	$105,646,770	$107,464,786	$111,445,651	$114,494,512	$117,951,035	$121,882,380	$125,437,113	$127,564,521
(B) UTILITY OPERATIONS:																			
(i) DISTRIBUTION O&M		$10,119,642	$10,706,512	$11,262,967	$11,845,443	$12,399,129	$12,809,731	$13,233,507	$13,670,879	$14,130,518	$14,612,833	$15,083,345	$15,568,352	$16,068,287	$16,583,654	$17,115,173	$17,587,884	$18,073,687	$19,503,524
(ii) CUSTOMER SERVICE		$3,328,488	$3,521,517	$3,704,543	$3,896,127	$4,078,242	$4,213,295	$4,352,680	$4,496,538	$4,647,719	$4,806,359	$4,961,117	$5,120,643	$5,285,078	$5,454,589	$5,629,413	$5,784,894	$5,944,681	$6,414,974
(iii) ADMINSTRATIVE & GENERAL		$11,131,227	$11,776,762	$12,388,842	$13,029,544	$13,638,577	$14,090,224	$14,556,362	$15,037,455	$15,543,040	$16,073,569	$16,591,115	$17,124,604	$17,674,514	$18,241,398	$18,826,049	$19,346,013	$19,880,379	$21,453,146
SUBTOTAL - UTILITY OPERATIONS		$24,579,357	$26,004,792	$27,356,351	$28,771,115	$30,115,948	$31,113,250	$32,142,550	$33,204,873	$34,321,277	$35,492,761	$36,635,577	$37,813,598	$39,027,879	$40,279,641	$41,570,635	$42,718,791	$43,898,747	$47,371,644
(C) PUBLIC PURPOSE PROGRAMS		$5,567,416	$5,663,259	$5,631,087	$5,890,543	$6,213,382	$6,416,466	$6,649,733	$6,788,689	$6,999,985	$7,364,850	$7,481,914	$7,635,763	$7,893,083	$8,110,770	$8,355,738	$8,605,202	$8,838,636	$8,845,256
(D) FRANCHISE FEES		$972,544	$996,858	$1,021,779	$1,047,324	$1,073,507	$1,100,344	$1,127,853	$1,156,049	$1,184,951	$1,214,574	$1,244,939	$1,276,062	$1,307,964	$1,340,663	$1,374,179	$1,408,534	$1,443,747	$1,479,841
(E) PROPERTY TAXES		$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131	$1,831,131
(F) NON-BYPASSABLE CHARGES		$7,045,213	$5,782,910	$4,337,924	$4,344,751	$4,609,667	$4,562,411	$4,509,458	$4,679,603	$4,660,510	$4,941,188	$5,031,449	$5,122,663	$5,214,848	$5,323,809	$5,476,958	$5,549,208	$5,622,487	$0
(G) OTHER "PASS-THROUGH" COSTS		$7,484,564	$8,259,857	$4,026,222	$4,926,163	$5,942,803	$6,574,605	$7,657,856	$7,809,797	$8,079,882	$8,700,279	$8,855,013	$9,011,154	$9,168,722	$9,359,669	$9,639,389	$9,762,876	$9,888,094	$10,015,067
TOTAL - OPERATING EXPENSES		$124,064,160	$126,199,915	$125,483,001	$131,264,724	$138,458,858	$142,984,371	$148,182,486	$151,278,986	$155,987,487	$164,118,130	$166,726,793	$170,155,158	$175,889,278	$180,740,194	$186,199,065	$191,758,122	$196,959,955	$197,107,458
(H) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$5,956,334	$5,692,182	$5,870,259	$5,749,493	$5,556,794	$5,678,455	$5,810,537	$5,715,861	$5,670,200	$5,380,233	$5,342,758	$5,437,345	$5,525,122	$5,414,974	$5,179,116	$5,277,053	$5,299,668	$4,979,426
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$5,956,334	$5,692,182	$5,870,259	$5,749,493	$5,556,794	$5,678,455	$5,810,537	$5,715,861	$5,670,200	$5,380,233	$5,342,758	$5,437,345	$5,525,122	$5,414,974	$5,179,116	$5,277,053	$5,299,668	$4,979,426
TOTAL EXPENSES NET OF MARKET REVENUES		$118,107,826	$120,507,733	$119,612,743	$125,515,230	$132,902,065	$137,305,917	$142,371,949	$145,563,125	$150,317,287	$158,737,897	$161,384,035	$164,717,813	$170,364,155	$175,325,220	$181,019,949	$186,481,068	$191,660,287	$192,128,032
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$130,398,011	$132,533,318	$130,092,246	$136,227,699	$145,137,222	$142,021,400	$147,433,192	$153,334,345	$161,157,683	$175,357,615	$181,965,664	$188,804,449	$195,882,166	$203,795,967	$213,627,234	$220,623,822	$223,538,155	$220,797,229
(B) CHULA VISTA REVENUE REQUIREMENT		$118,107,826	$120,507,733	$119,612,743	$125,515,230	$132,902,065	$137,305,917	$142,371,949	$145,563,125	$150,317,287	$158,737,897	$161,384,035	$164,717,813	$170,364,155	$175,325,220	$181,019,949	$186,481,068	$191,660,287	$192,128,032
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	$109,331,806	$12,290,184	$12,025,585	$10,479,503	$10,712,468	$12,235,158	$4,715,483	$5,061,243	$7,771,220	$10,840,395	$16,619,717	$20,581,629	$24,086,636	$25,518,011	$28,470,747	$32,607,285	$34,142,753	$31,877,869	$28,669,197
(D) BENEFITS	9.3%	9.4%	9.1%	8.1%	7.9%	8.4%	3.3%	3.4%	5.1%	6.7%	9.5%	11.3%	12.8%	13.0%	14.0%	15.3%	15.5%	14.3%	13.0%
NPV 2006-2023	$109,331,806	$12,290,184	$12,025,585	$10,479,503	$10,712,468	$12,235,158	$4,715,483	$5,061,243	$7,771,220	$10,840,395	$16,619,717	$20,581,629	$24,086,636	$25,518,011	$28,470,747	$32,607,285	$34,142,753	$31,877,869	$28,669,197
NPV 2006-2014	$52,163,939	$12,290,184	$12,025,585	$10,479,503	$10,712,468	$12,235,158	$4,715,483	$5,061,243	$7,771,220	$10,840,395									
NPV 2015-2023	$57,167,866	0	0	0	0	0	0	0	0	0	$16,619,717	$20,581,629	$24,086,636	$25,518,011	$28,470,747	$32,607,285	$34,142,753	$31,877,869	$28,669,197

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME
COMBINED CCA/GREENFIELD, CCA AREAS - CONTRACTS

CATEGORY	NPV	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		70,734	72,308	73,618	74,929	76,239	76,606	76,973	77,340	77,707	78,074	78,440	78,807	79,174	79,541	79,908	80,012	80,116	80,219
(B) SMALL COMMERCIAL (A)		3,225	3,265	3,304	3,345	3,363	3,382	3,400	3,419	3,438	3,468	3,498	3,528	3,559	3,589	3,619	3,648	3,678	3,709
(C) MEDIUM COMMERCIAL (AL-TOU)		328	332	336	340	342	344	345	347	349	352	355	358	361	365	368	371	374	377
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		13	13	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		4,162	4,267	4,375	4,485	4,172	4,277	4,385	4,496	4,609	4,649	4,689	4,730	4,770	4,812	4,851	4,891	4,931	9,956
SUBTOTAL - CUSTOMER ACCOUNTS		78,462	80,184	81,646	83,112	84,130	84,623	85,118	85,616	86,117	86,557	86,997	87,438	87,879	88,321	88,760	88,937	89,114	94,276
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		354,850,021	367,847,613	379,784,441	391,984,350	404,452,381	412,116,513	419,916,247	427,853,881	435,931,751	444,152,232	452,517,739	461,030,724	469,693,682	478,509,148	487,479,698	494,981,097	502,597,081	510,329,390
(B) SMALL COMMERCIAL (A)		59,004,814	59,723,349	60,450,635	61,186,777	61,525,484	61,866,067	62,208,535	62,552,899	62,899,169	63,442,484	63,990,492	64,543,234	65,100,751	65,663,083	66,202,284	66,745,912	67,294,005	67,846,598
(C) MEDIUM COMMERCIAL (AL-TOU)		203,134,744	205,608,432	208,112,243	210,646,545	211,812,608	212,985,126	214,164,134	215,349,669	216,541,766	218,412,227	220,298,844	222,201,758	224,121,109	226,057,039	227,913,336	229,784,875	231,671,783	233,574,186
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		150,011,930	151,838,711	153,687,738	155,559,281	156,420,401	157,286,287	158,156,967	159,032,467	159,912,813	161,294,119	162,687,358	164,092,631	165,510,043	166,939,698	168,310,544	169,692,648	171,086,101	172,490,997
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		7,321,167	7,505,737	7,694,960	7,888,953	7,338,790	7,523,804	7,713,482	7,907,942	8,107,305	8,177,335	8,247,970	8,319,214	8,391,075	8,463,556	8,533,055	8,603,126	8,673,771	8,744,997
SUBTOTAL - LOAD REQUIREMENTS		774,322,676	792,523,842	809,730,016	827,265,906	841,549,663	851,777,797	862,159,365	872,696,857	883,392,804	895,478,398	907,742,403	920,187,562	932,816,660	945,632,524	958,438,918	969,807,658	981,322,742	992,986,168
III. ESTIMATED SDG&E RATES ($/KWH):																			
(A) RESIDENTIAL		$0.075	$0.073	$0.071	$0.071	$0.072	$0.066	$0.067	$0.069	$0.070	$0.072	$0.073	$0.075	$0.077	$0.079	$0.081	$0.082	$0.082	$0.078
(B) SMALL COMMERCIAL (A)		$0.095	$0.092	$0.089	$0.090	$0.090	$0.083	$0.084	$0.087	$0.088	$0.091	$0.093	$0.095	$0.097	$0.099	$0.102	$0.104	$0.104	$0.100
(C) MEDIUM COMMERCIAL (AL-TOU)		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.099
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.099
(E) AGRICULTURAL		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.098
(F) STREET LIGHTING AND TRAFFIC CONTROL		$0.086	$0.084	$0.081	$0.082	$0.082	$0.075	$0.077	$0.079	$0.080	$0.082	$0.084	$0.086	$0.088	$0.090	$0.092	$0.095	$0.095	$0.090
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
(A) RESIDENTIAL		26,720,653	26,834,945	26,903,262	27,972,035	29,034,024	27,072,848	28,141,898	29,376,092	30,561,811	31,853,868	33,217,259	34,639,395	36,122,807	37,670,131	39,284,119	40,833,432	41,461,712	39,938,115
(B) SMALL COMMERCIAL (A)		5,600,451	5,490,768	5,394,660	5,503,914	5,567,496	5,118,724	5,254,945	5,413,999	5,563,162	5,742,539	5,930,170	6,124,095	6,324,526	6,531,682	6,742,941	6,961,202	7,018,365	6,788,636
(C) MEDIUM COMMERCIAL (AL-TOU)		19,000,219	18,628,293	18,302,615	18,672,643	18,888,337	17,366,667	17,828,062	18,367,564	18,872,769	19,480,847	20,117,022	20,774,532	21,454,098	22,156,465	22,872,733	23,612,738	23,806,637	23,012,837
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		14,031,374	13,756,712	13,516,204	13,789,464	13,948,751	12,825,021	13,165,753	13,564,167	13,937,254	14,386,311	14,856,116	15,341,677	15,843,526	16,362,213	16,891,166	17,437,649	17,580,841	16,994,631
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
(F) STREET LIGHTING AND TRAFFIC CONTROL		631,448	627,095	624,141	644,830	603,446	565,846	592,096	621,929	651,369	672,266	694,151	716,770	740,147	764,308	788,945	814,398	821,086	790,789
TOTAL REVENUE REQUIREMENT		$65,984,146	$65,337,813	$64,740,881	$66,582,885	$68,042,054	$62,949,107	$64,982,756	$67,343,751	$69,586,365	$72,135,831	$74,814,718	$77,596,469	$80,485,104	$83,484,799	$86,579,904	$89,659,419	$90,688,640	$87,525,009
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$3,069,022	$3,468,924	$3,649,128	$4,182,111	$4,539,864	$8,794,654	$8,646,323	$9,200,248	$8,972,085	$9,228,428	$428,823	$403,770	$520,773	$606,872	$691,967	$1,532,210	$1,911,793	$2,171,945
(ii) CONTRACT PURCHASES		$41,500,040	$41,894,240	$42,866,600	$43,322,120	$43,777,640	$41,576,040	$42,636,000	$42,636,000	$43,582,080	$44,055,120	$59,295,600	$60,688,440	$60,609,600	$60,609,600	$60,609,600	$62,783,160	$62,783,160	$62,783,160
(iii) POWER PRODUCTION		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(iv) DWR POWER		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) OPERATIONS AND SCHEDULING		$3,935,807	$3,981,310	$4,024,325	$4,068,165	$4,103,874	$4,129,444	$4,155,398	$4,181,742	$4,208,482	$4,238,696	$4,269,356	$4,300,469	$4,332,042	$4,364,081	$4,396,097	$4,424,519	$4,453,307	$4,482,465
(vi) ANCILLARY SERVICES & CAPACITY RESERVES		$1,727,410	$1,713,950	$1,796,044	$1,845,523	$1,877,379	$1,925,621	$1,978,501	$1,991,523	$2,023,467	$2,051,149	$2,048,278	$2,056,743	$2,144,630	$2,214,414	$2,273,008	$2,357,860	$2,465,354	$2,473,649
(vi) CALIFORNIA ISO COSTS		$1,808,829	$1,895,461	$1,992,174	$2,090,456	$2,184,367	$2,273,561	$2,366,872	$2,461,361	$2,561,182	$2,668,414	$2,982,892	$3,126,668	$3,220,365	$3,331,630	$3,445,772	$3,496,631	$3,626,276	$3,752,491
SUBTOTAL - POWER SUPPLY		$52,041,107	$52,953,885	$54,328,271	$55,508,375	$56,483,124	$58,699,321	$59,783,095	$60,470,874	$61,347,295	$62,241,807	$69,024,949	$70,576,089	$70,827,410	$71,126,596	$71,416,445	$74,594,380	$75,239,890	$75,663,710
(B) NON-BYPASSABLE CHARGES		$8,799,844	$8,150,730	$6,898,452	$7,566,091	$8,313,626	$8,709,575	$9,463,848	$9,635,516	$9,604,694	$9,698,854	$9,825,209	$9,953,363	$10,083,342	$10,215,174	$10,346,451	$10,464,301	$10,583,617	$6,498,677
TOTAL - OPERATING EXPENSES		$60,840,951	$61,104,615	$61,226,724	$63,074,465	$64,796,750	$67,408,896	$69,246,943	$70,106,389	$70,951,990	$71,940,661	$78,850,158	$80,529,452	$80,910,752	$81,341,770	$81,762,896	$85,058,681	$85,823,507	$82,162,387
(C) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$123,766	$59,981	$48,403	$16,842	$1,833	$0	$0	$0	$0	$0	$4,019,138	$4,403,771	$3,732,978	$3,295,005	$2,823,704	$1,248,784	$992,771	$703,838
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$123,766	$59,981	$48,403	$16,842	$1,833	$0	$0	$0	$0	$0	$4,019,138	$4,403,771	$3,732,978	$3,295,005	$2,823,704	$1,248,784	$992,771	$703,838
TOTAL EXPENSES NET OF MARKET REVENUES		$60,717,185	$61,044,634	$61,178,321	$63,057,624	$64,794,918	$67,408,896	$69,246,943	$70,106,389	$70,951,990	$71,940,661	$74,831,020	$76,125,681	$77,177,773	$78,046,766	$78,939,192	$83,809,896	$84,830,736	$81,458,549
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$65,984,146	$65,337,813	$64,740,881	$66,582,885	$68,042,054	$62,949,107	$64,982,756	$67,343,751	$69,586,365	$72,135,831	$74,814,718	$77,596,469	$80,485,104	$83,484,799	$86,579,904	$89,659,419	$90,688,640	$87,525,009
(B) CHULA VISTA REVENUE REQUIREMENT		$60,717,185	$61,044,634	$61,178,321	$63,057,624	$64,794,918	$67,408,896	$69,246,943	$70,106,389	$70,951,990	$71,940,661	$74,831,020	$76,125,681	$77,177,773	$78,046,766	$78,939,192	$83,809,896	$84,830,736	$81,458,549
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	$15,585,152	$5,266,961	$4,293,179	$3,562,560	$3,525,261	$3,247,136	($4,459,790)	($4,264,188)	($2,762,638)	($1,365,625)	$195,171	($16,302)	$1,470,788	$3,307,330	$5,438,034	$7,640,712	$5,849,523	$5,857,904	$6,066,459
(D) BENEFITS (% OF GENERATION RATES)	3.0%	8.0%	6.6%	5.5%	5.3%	4.8%	-7.1%	-6.6%	-4.1%	-2.0%	0.3%	0.0%	1.9%	4.1%	6.5%	8.8%	6.5%	6.5%	6.9%
(E) BENEFITS (% OF TOTAL RATES)	1.6%	4.5%	3.6%	3.1%	2.9%	2.6%	-3.7%	-3.5%	-2.2%	-1.0%	0.1%	0.0%	1.0%	2.2%	3.5%	4.8%	3.6%	3.5%	3.7%
NPV 2006-2023	$15,585,152	$5,266,961	$4,293,179	$3,562,560	$3,525,261	$3,247,136	($4,459,790)	($4,264,188)	($2,762,638)	($1,365,625)	$195,171	($16,302)	$1,470,788	$3,307,330	$5,438,034	$7,640,712	$5,849,523	$5,857,904	$6,066,459
NPV 2006-2014	$8,057,512	$5,266,961	$4,293,179	$3,562,560	$3,525,261	$3,247,136	($4,459,790)	($4,264,188)	($2,762,638)	($1,365,625)									
NPV 2015-2023	$7,527,641	0	0	0	0	0	0	0	0	0	$195,171	($16,302)	$1,470,788	$3,307,330	$5,438,034	$7,640,712	$5,849,523	$5,857,904	$6,066,459

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME
COMBINED CCA/GREENFIELD, GREENFIELD AREAS - CONTRACTS

CATEGORY	NPV	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		3,706	4,632	5,404	6,176	6,948	7,164	7,380	7,596	7,812	8,028	8,244	8,460	8,676	8,892	9,108	9,169	9,230	9,291
(B) SMALL COMMERCIAL (A)		225	230	236	261	326	328	331	333	382	524	526	528	531	533	536	545	554	563
(C) MEDIUM COMMERCIAL (AL-TOU)		85	86	87	102	149	163	176	190	212	254	265	277	288	299	315	321	326	332
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		1	1	1	1	2	2	2	2	2	5	5	5	5	6	7	7	7	7
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS		4,017	4,950	5,728	6,540	7,424	7,656	7,888	8,120	8,408	8,811	9,040	9,270	9,499	9,729	9,965	10,041	10,117	10,193
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		18,591,656	23,566,550	27,879,178	32,308,498	36,856,940	38,537,519	40,258,094	42,019,457	43,822,415	45,667,789	47,556,418	49,489,151	51,466,857	53,490,419	55,560,735	56,505,268	57,465,857	58,442,777
(B) SMALL COMMERCIAL (A)		4,111,043	4,212,076	4,313,109	4,773,129	5,956,766	6,004,269	6,051,772	6,099,274	6,992,499	9,578,980	9,622,317	9,665,654	9,708,991	9,752,328	9,798,900	9,965,481	10,134,894	10,307,187
(C) MEDIUM COMMERCIAL (AL-TOU)		52,827,615	53,433,812	54,040,008	63,357,636	92,311,842	100,779,730	109,247,618	117,715,506	131,257,727	157,608,048	164,592,842	171,577,636	178,562,430	185,547,224	195,457,126	198,779,897	202,159,155	205,595,861
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		12,333,130	12,636,229	12,939,327	14,319,387	17,870,299	18,012,807	18,155,315	18,297,823	26,017,762	58,293,796	58,423,808	58,553,819	58,683,831	62,542,446	73,867,972	75,123,728	76,400,831	77,699,646
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS		87,863,444	93,848,667	99,171,623	114,758,650	152,995,847	163,334,325	173,712,799	184,132,061	208,090,402	271,148,613	280,195,384	289,286,261	298,422,109	311,332,418	334,684,733	340,374,374	346,160,738	352,045,471
III. ESTIMATED SDG&E RATES ($/KWH):																			
RESIDENTIAL		$0.157	$0.155	$0.144	$0.146	$0.147	$0.141	$0.143	$0.146	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.167	$0.171	$0.171	$0.166
SMALL COMMERCIAL (A)		$0.179	$0.177	$0.165	$0.167	$0.169	$0.162	$0.165	$0.168	$0.171	$0.174	$0.178	$0.181	$0.185	$0.189	$0.192	$0.196	$0.196	$0.192
MEDIUM COMMERCIAL (AL-TOU)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
AGRICULTURAL		$0.167	$0.165	$0.164	$0.165	$0.167	$0.160	$0.163	$0.166	$0.169	$0.172	$0.175	$0.179	$0.182	$0.185	$0.189	$0.192	$0.192	$0.188
STREET LIGHTING & TRAFFIC CONTROL		$0.111	$0.109	$0.108	$0.109	$0.110	$0.106	$0.108	$0.110	$0.112	$0.114	$0.116	$0.118	$0.120	$0.122	$0.124	$0.127	$0.127	$0.123
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
RESIDENTIAL		2,914,995	3,651,137	4,013,350	4,701,460	5,415,985	5,423,090	5,767,630	6,141,410	6,523,946	6,931,097	7,360,201	7,810,688	8,283,539	8,779,780	9,300,480	9,646,429	9,810,418	9,729,664
SMALL COMMERCIAL (A)		737,544	746,720	713,407	798,179	1,005,866	971,081	996,578	1,024,584	1,196,616	1,671,198	1,711,875	1,753,548	1,796,243	1,839,985	1,885,422	1,955,535	1,988,779	1,978,933
MEDIUM COMMERCIAL (AL-TOU)		7,540,950	7,536,737	7,544,470	8,934,206	13,136,967	13,771,488	15,179,424	16,665,552	18,904,410	23,113,789	24,585,611	26,105,197	27,673,970	29,293,396	31,435,429	32,569,542	33,123,224	32,815,528
LARGE INDUSTRIAL (AL-TOU, + 500 KW)		1,760,510	1,782,316	1,806,446	2,019,210	2,543,136	2,461,439	2,522,593	2,590,511	3,747,211	8,548,995	8,726,899	8,908,848	9,094,940	9,873,932	11,880,209	12,308,817	12,518,067	12,401,781
AGRICULTURAL		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
STREET LIGHTING & TRAFFIC CONTROL		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL REVENUE REQUIREMENT		$12,953,999	$13,716,910	$14,077,672	$16,453,055	$22,101,954	$22,627,097	$24,466,225	$26,422,057	$30,372,184	$40,265,079	$42,384,586	$44,578,281	$46,848,693	$49,787,093	$54,501,540	$56,480,323	$57,440,488	$56,925,906
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$92,684	$182,513	$307,231	$1,009,841	$0	$58,602	$149,238	$223,143	$1,047,300	$313,988	$526,959	$793,209	$618,609	$1,100,444	$713,511	$718,072	$911,985	$1,121,930
(ii) CONTRACT PURCHASES		$5,594,200	$5,585,440	$5,594,200	$5,594,200	$10,731,840	$10,749,360	$10,766,880	$11,239,920	$11,239,920	$16,801,400	$16,757,600	$16,757,600	$17,808,800	$17,808,800	$21,075,400	$21,767,440	$21,767,440	$21,767,440
(iii) POWER PRODUCTION		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(iv) DWR POWER		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) TRANSMISSION AND SCHEDULING		$800,429	$834,570	$869,243	$991,210	$1,537,133	$1,582,623	$1,631,346	$1,732,328	$1,890,271	$2,580,228	$2,651,729	$2,730,986	$2,866,803	$2,975,906	$3,305,814	$3,409,270	$3,472,798	$3,542,093
(vi) DISTRIBUTION		$1,290,452	$1,569,829	$1,802,855	$2,045,992	$2,310,514	$2,380,062	$2,449,610	$2,519,158	$2,605,200	$2,725,794	$2,794,557	$2,863,321	$2,932,084	$3,000,946	$3,071,472	$3,094,149	$3,116,901	$3,139,728
(vii) CALIFORNIA ISO COSTS		$481,804	$508,780	$538,477	$623,631	$1,006,370	$1,049,685	$1,096,952	$1,185,802	$1,310,982	$1,833,103	$1,915,838	$2,007,764	$2,151,752	$2,273,766	$2,582,064	$2,716,744	$2,820,070	$2,928,991
(viii) ANCILLARY SERVICES & CAPACITY RESERVES		$196,440	$203,381	$220,405	$256,540	$342,136	$370,190	$399,699	$421,355	$477,848	$622,068	$633,305	$647,727	$687,354	$730,360	$794,984	$828,851	$871,030	$878,323
SUBTOTAL - POWER SUPPLY AND DELIVERY		$8,456,009	$8,884,514	$9,332,410	$10,521,415	$15,927,993	$16,190,523	$16,493,724	$17,321,706	$18,571,521	$24,876,580	$25,279,988	$25,800,607	$27,065,402	$27,890,223	$31,543,246	$32,534,526	$32,960,224	$33,378,504
(B) UTILITY OPERATIONS:																			
(i) DISTRIBUTION O&M		$492,856	$622,514	$738,393	$864,138	$1,005,382	$1,062,758	$1,122,375	$1,184,309	$1,256,873	$1,350,005	$1,419,822	$1,492,287	$1,567,488	$1,645,571	$1,727,543	$1,784,189	$1,842,633	$1,902,931
(ii) CUSTOMER SERVICE		$162,107	$204,753	$242,867	$284,227	$330,684	$349,556	$369,165	$389,535	$413,402	$444,035	$466,999	$490,834	$515,568	$541,251	$568,212	$586,844	$606,067	$625,900
(iii) ADMINSTRATIVE & GENERAL		$542,123	$684,742	$812,204	$950,520	$1,105,882	$1,168,994	$1,234,571	$1,302,696	$1,382,513	$1,484,955	$1,561,752	$1,641,460	$1,724,178	$1,810,067	$1,900,232	$1,962,541	$2,026,827	$2,093,152
SUBTOTAL - UTILITY OPERATIONS		$1,197,085	$1,512,009	$1,793,464	$2,098,885	$2,441,947	$2,581,308	$2,726,111	$2,876,540	$3,052,788	$3,278,995	$3,448,573	$3,624,580	$3,807,233	$3,996,889	$4,195,987	$4,333,574	$4,475,527	$4,621,983
(C) PUBLIC PURPOSE PROGRAMS		$520,740	$556,656	$572,946	$653,860	$948,653	$976,084	$1,009,784	$1,062,499	$1,142,415	$1,486,821	$1,518,941	$1,556,892	$1,630,140	$1,685,309	$1,880,075	$1,936,426	$1,966,465	$1,926,368
(D) FRANCHISE FEES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(E) PROPERTY TAXES		$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331
(F) NON-BYPASSABLE CHARGES		$717,962	$612,292	$473,317	$529,283	$709,128	$734,104	$756,223	$815,331	$888,523	$1,148,436	$1,186,753	$1,225,257	$1,263,951	$1,318,632	$1,417,540	$1,441,638	$1,466,146	$0
(G) OTHER "PASS-THROUGH" COSTS		$583,031	$709,700	$466,051	$637,817	$982,709	$1,139,681	$1,386,839	$1,471,301	$1,672,970	$2,212,116	$2,284,468	$2,357,076	$2,429,946	$2,535,011	$2,729,371	$2,775,770	$2,822,959	$2,870,949
TOTAL - OPERATING EXPENSES		$11,604,158	$12,404,500	$12,767,520	$14,570,589	$21,139,760	$21,751,031	$22,502,013	$23,676,707	$25,457,547	$33,132,278	$33,848,053	$34,693,743	$36,326,003	$37,555,395	$41,895,550	$43,151,265	$43,820,650	$42,927,135
(H) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$444,506	$256,365	$130,359	$0	$1,267,597	$886,285	$516,337	$446,893	$33,074	$628,698	$396,431	$211,751	$331,946	$121,879	$484,237	$574,292	$446,900	$330,059
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$444,506	$256,365	$130,359	$0	$1,267,597	$886,285	$516,337	$446,893	$33,074	$628,698	$396,431	$211,751	$331,946	$121,879	$484,237	$574,292	$446,900	$330,059
TOTAL EXPENSES NET OF MARKET REVENUES		$11,159,652	$12,148,135	$12,637,162	$14,570,589	$19,872,164	$20,864,746	$21,985,675	$23,229,815	$25,424,473	$32,503,580	$33,451,622	$34,481,992	$35,994,057	$37,433,516	$41,411,313	$42,576,973	$43,373,750	$42,597,075
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$12,953,999	$13,716,910	$14,077,672	$16,453,055	$22,101,954	$22,627,097	$24,466,225	$26,422,057	$30,372,184	$40,265,079	$42,384,586	$44,578,281	$46,848,693	$49,787,093	$54,501,540	$56,480,323	$57,440,488	$56,925,906
(B) CHULA VISTA REVENUE REQUIREMENT		$11,159,652	$12,148,135	$12,637,162	$14,570,589	$19,872,164	$20,864,746	$21,985,675	$23,229,815	$25,424,473	$32,503,580	$33,451,622	$34,481,992	$35,994,057	$37,433,516	$41,411,313	$42,576,973	$43,373,750	$42,597,075
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	$36,175,271	$1,794,347	$1,568,775	$1,440,510	$1,882,466	$2,229,791	$1,762,351	$2,480,550	$3,192,243	$4,947,710	$7,761,499	$8,932,964	$10,096,290	$10,854,636	$12,353,578	$13,090,228	$13,903,350	$14,066,738	$14,328,831
(D) BENEFITS	17.5%	13.9%	11.4%	10.2%	11.4%	10.1%	7.8%	10.1%	12.1%	16.3%	19.3%	21.1%	22.6%	23.2%	24.8%	24.0%	24.6%	24.5%	25.2%
NPV 2006-2023	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
NPV 2006-2014	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!									
NPV 2015-2023	#REF!	0	0	0	0	0	0	0	0	0	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME

COMBINED CCA/GREENFIELD, CCA AREAS - GENERATION

CATEGORY	NPV	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		70,734	72,308	73,618	74,929	76,239	76,606	76,973	77,340	77,707	78,074	78,440	78,807	79,174	79,541	79,908	80,012	80,116	80,219
(B) SMALL COMMERCIAL (A)		3,225	3,265	3,304	3,345	3,363	3,382	3,400	3,419	3,438	3,468	3,498	3,528	3,559	3,589	3,619	3,648	3,678	3,709
(C) MEDIUM COMMERCIAL (AL-TOU)		328	332	336	340	342	344	345	347	349	352	355	358	361	365	368	371	374	377
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		13	13	14	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		4,162	4,267	4,375	4,485	4,172	4,277	4,385	4,496	4,609	4,649	4,689	4,730	4,770	4,812	4,851	4,891	4,931	9,956
SUBTOTAL - CUSTOMER ACCOUNTS		78,462	80,184	81,646	83,112	84,130	84,623	85,118	85,616	86,117	86,557	86,997	87,438	87,879	88,321	88,760	88,937	89,114	94,276
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		354,850,021	367,847,613	379,784,441	391,984,350	404,452,381	412,116,513	419,916,247	427,853,881	435,931,751	444,152,232	452,517,739	461,030,724	469,693,682	478,509,148	487,479,698	494,981,097	502,597,081	510,329,390
(B) SMALL COMMERCIAL (A)		59,004,814	59,723,349	60,450,635	61,186,777	61,525,484	61,866,067	62,208,535	62,552,899	62,899,169	63,442,484	63,990,492	64,543,234	65,100,751	65,663,083	66,202,284	66,745,912	67,294,005	67,846,598
(C) MEDIUM COMMERCIAL (AL-TOU)		203,134,744	205,608,432	208,112,243	210,646,545	211,812,608	212,985,126	214,164,134	215,349,669	216,541,766	218,412,227	220,298,844	222,201,758	224,121,109	226,057,039	227,913,336	229,784,875	231,671,783	233,574,186
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		150,011,930	151,838,711	153,687,738	155,559,281	156,420,401	157,286,287	158,156,967	159,032,467	159,912,813	161,294,119	162,687,358	164,092,631	165,510,043	166,939,698	168,310,544	169,692,648	171,086,101	172,490,997
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		7,321,167	7,505,737	7,694,960	7,888,953	7,338,790	7,523,804	7,713,482	7,907,942	8,107,305	8,177,335	8,247,970	8,319,214	8,391,075	8,463,556	8,533,055	8,603,126	8,673,771	8,744,997
SUBTOTAL - LOAD REQUIREMENTS		774,322,676	792,523,842	809,730,016	827,265,906	841,549,663	851,777,797	862,159,365	872,696,857	883,392,804	895,478,398	907,742,403	920,187,562	932,816,660	945,632,524	958,438,918	969,807,658	981,322,742	992,986,168
III. ESTIMATED SDG&E RATES ($/KWH):																			
RESIDENTIAL		$0.075	$0.073	$0.071	$0.071	$0.072	$0.066	$0.067	$0.069	$0.070	$0.072	$0.073	$0.075	$0.077	$0.079	$0.081	$0.082	$0.082	$0.078
SMALL COMMERCIAL (A)		$0.095	$0.092	$0.089	$0.090	$0.090	$0.083	$0.084	$0.087	$0.088	$0.091	$0.093	$0.095	$0.097	$0.099	$0.102	$0.104	$0.104	$0.100
MEDIUM COMMERCIAL (AL-TOU)		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.099
LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.099
AGRICULTURAL		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.098
STREET LIGHTING & TRAFFIC CONTROL		$0.086	$0.084	$0.081	$0.082	$0.082	$0.075	$0.077	$0.079	$0.080	$0.082	$0.084	$0.086	$0.088	$0.090	$0.092	$0.095	$0.095	$0.090
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
RESIDENTIAL		26,720,653	26,834,945	26,903,262	27,972,035	29,034,024	27,072,848	28,141,898	29,376,092	30,561,811	31,853,868	33,217,259	34,639,395	36,122,807	37,670,131	39,284,119	40,833,432	41,461,712	39,938,115
SMALL COMMERCIAL (A)		5,600,451	5,490,768	5,394,660	5,503,914	5,567,496	5,118,724	5,254,945	5,413,999	5,563,162	5,742,539	5,930,170	6,124,095	6,324,526	6,531,682	6,742,941	6,961,202	7,018,365	6,788,636
MEDIUM COMMERCIAL (AL-TOU)		19,000,219	18,628,293	18,302,615	18,672,643	18,888,337	17,366,667	17,828,062	18,367,564	18,872,769	19,480,847	20,117,022	20,774,532	21,454,098	22,156,465	22,872,733	23,612,738	23,806,637	23,012,837
LARGE INDUSTRIAL (AL-TOU, + 500 KW)		14,031,374	13,756,712	13,516,204	13,789,464	13,948,751	12,825,021	13,165,753	13,564,167	13,937,254	14,386,311	14,856,116	15,341,677	15,843,526	16,362,213	16,891,166	17,437,649	17,580,841	16,994,631
AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
STREET LIGHTING & TRAFFIC CONTROL		631,448	627,095	624,141	644,830	603,446	565,846	592,096	621,929	651,369	672,266	694,151	716,770	740,147	764,308	788,945	814,398	821,086	790,789
TOTAL REVENUE REQUIREMENT		$65,984,146	$65,337,813	$64,740,881	$66,582,885	$68,042,054	$62,949,107	$64,982,756	$67,343,751	$69,586,365	$72,135,831	$74,814,718	$77,596,469	$80,485,104	$83,484,799	$86,579,904	$89,659,419	$90,688,640	$87,525,009
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$4,382,988	$4,772,828	$5,101,126	$5,639,969	$6,018,082	$5,984,739	$5,966,492	$6,420,334	$6,350,349	$6,619,675	$6,503,938	$6,145,811	$7,209,769	$7,955,296	$8,675,896	$9,457,172	$10,361,424	$10,622,024
(ii) CONTRACT PURCHASES		$2,733,120	$3,127,320	$4,099,680	$4,555,200	$5,010,720	$6,035,640	$7,095,600	$7,095,600	$8,041,680	$8,514,720	$9,285,600	$10,678,440	$10,599,600	$10,599,600	$10,599,600	$11,177,760	$11,177,760	$11,177,760
(iii) POWER PRODUCTION		$37,685,260	$36,690,110	$37,498,670	$37,685,260	$37,685,260	$38,120,638	$38,618,214	$38,431,623	$38,556,017	$38,556,017	$38,058,442	$37,747,457	$38,680,410	$39,302,379	$39,737,757	$40,608,514	$41,790,254	$41,479,270
(iv) DWR POWER		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) OPERATIONS AND SCHEDULING		$3,935,807	$3,981,310	$4,024,325	$4,068,165	$4,103,874	$4,129,444	$4,155,398	$4,181,742	$4,208,482	$4,238,696	$4,269,356	$4,300,469	$4,332,042	$4,364,081	$4,396,097	$4,424,519	$4,453,307	$4,482,465
(vi) ANCILLARY SERVICES & CAPACITY RESERVES		$1,359,220	$1,365,826	$1,447,536	$1,503,757	$1,542,740	$1,591,678	$1,644,849	$1,665,111	$1,701,316	$1,735,192	$1,743,217	$1,760,787	$1,846,700	$1,917,673	$1,979,280	$2,062,922	$2,167,060	$2,184,422
(vi) CALIFORNIA ISO COSTS		$815,424	$880,250	$952,401	$1,022,752	$1,089,508	$1,155,727	$1,225,239	$1,285,342	$1,360,996	$1,436,971	$1,522,549	$1,619,189	$1,694,724	$1,780,468	$1,869,478	$1,958,516	$2,052,072	$2,139,273
SUBTOTAL - POWER SUPPLY		$50,911,818	$50,817,643	$53,123,737	$54,475,103	$55,450,184	$57,017,867	$58,705,792	$59,079,751	$60,218,841	$61,101,270	$61,383,102	$62,252,152	$64,363,245	$65,919,498	$67,258,108	$69,689,403	$72,001,877	$72,085,215
(B) NON-BYPASSABLE CHARGES		$8,799,844	$8,150,730	$6,898,452	$7,566,091	$8,313,626	$8,709,575	$9,463,848	$9,635,516	$9,604,694	$9,698,854	$9,825,209	$9,953,363	$10,083,342	$10,215,174	$10,346,451	$10,464,301	$10,583,617	$6,498,677
TOTAL - OPERATING EXPENSES		$59,711,662	$58,968,373	$60,022,189	$62,041,194	$63,763,810	$65,727,442	$68,169,640	$68,715,267	$69,823,535	$70,800,124	$71,208,310	$72,205,515	$74,446,586	$76,134,672	$77,604,559	$80,153,704	$82,585,494	$78,583,892
(C) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$5,153,015	$4,958,025	$5,157,989	$5,154,009	$5,154,270	$5,351,961	$5,562,071	$5,444,803	$5,591,575	$5,601,311	$5,631,660	$5,794,300	$5,750,285	$5,751,258	$5,717,647	$5,763,947	$5,853,835	$5,577,765
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$5,153,015	$4,958,025	$5,157,989	$5,154,009	$5,154,270	$5,351,961	$5,562,071	$5,444,803	$5,591,575	$5,601,311	$5,631,660	$5,794,300	$5,750,285	$5,751,258	$5,717,647	$5,763,947	$5,853,835	$5,577,765
TOTAL EXPENSES NET OF MARKET REVENUES		$54,558,648	$54,010,348	$54,864,200	$56,887,185	$58,609,540	$60,375,481	$62,607,569	$63,270,463	$64,231,960	$65,198,813	$65,576,651	$66,411,215	$68,696,301	$70,383,414	$71,886,911	$74,389,756	$76,731,659	$73,006,127
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$65,984,146	$65,337,813	$64,740,881	$66,582,885	$68,042,054	$62,949,107	$64,982,756	$67,343,751	$69,586,365	$72,135,831	$74,814,718	$77,596,469	$80,485,104	$83,484,799	$86,579,904	$89,659,419	$90,688,640	$87,525,009
(B) CHULA VISTA REVENUE REQUIREMENT		$54,558,648	$54,010,348	$54,864,200	$56,887,185	$58,609,540	$60,375,481	$62,607,569	$63,270,463	$64,231,960	$65,198,813	$65,576,651	$66,411,215	$68,696,301	$70,383,414	$71,886,911	$74,389,756	$76,731,659	$73,006,127
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	$68,222,676	$11,425,498	$11,327,465	$9,876,681	$9,695,701	$9,432,514	$2,573,625	$2,375,186	$4,073,288	$5,354,405	$6,937,018	$9,238,067	$11,185,254	$11,788,802	$13,101,385	$14,692,993	$15,269,663	$13,956,981	$14,518,881
(D) BENEFITS (% OF GENERATION RATES)	13.0%	17.3%	17.3%	15.3%	14.6%	13.9%	4.1%	3.7%	6.0%	7.7%	9.6%	12.3%	14.4%	14.6%	15.7%	17.0%	17.0%	15.4%	16.6%
(E) BENEFITS (% OF TOTAL RATES)	7.1%	9.7%	9.5%	8.5%	8.1%	7.7%	2.2%	1.9%	3.2%	4.1%	5.1%	6.6%	7.8%	7.9%	8.5%	9.2%	9.3%	8.4%	8.9%
NPV 2006-2023	$68,222,676	$11,425,498	$11,327,465	$9,876,681	$9,695,701	$9,432,514	$2,573,625	$2,375,186	$4,073,288	$5,354,405	$6,937,018	$9,238,067	$11,185,254	$11,788,802	$13,101,385	$14,692,993	$15,269,663	$13,956,981	$14,518,881
NPV 2006-2014	$42,264,179	$11,425,498	$11,327,465	$9,876,681	$9,695,701	$9,432,514	$2,573,625	$2,375,186	$4,073,288	$5,354,405									
NPV 2015-2023	$25,958,496	0	0	0	0	0	0	0	0	0	$6,937,018	$9,238,067	$11,185,254	$11,788,802	$13,101,385	$14,692,993	$15,269,663	$13,956,981	$14,518,881

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME
COMBINED CCA/GREENFIELD, GREENFIELD AREAS - GENERATION

CATEGORY	NPV	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		3,706	4,632	5,404	6,176	6,948	7,164	7,380	7,596	7,812	8,028	8,244	8,460	8,676	8,892	9,108	9,169	9,230	9,291
(B) SMALL COMMERCIAL (A)		225	230	236	261	326	328	331	333	382	524	526	528	531	533	536	545	554	563
(C) MEDIUM COMMERCIAL (AL-TOU)		85	86	87	102	149	163	176	190	212	254	265	277	288	299	315	321	326	332
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		1	1	1	1	2	2	2	2	2	5	5	5	5	6	7	7	7	7
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS		4,017	4,950	5,728	6,540	7,424	7,656	7,888	8,120	8,408	8,811	9,040	9,270	9,499	9,729	9,965	10,041	10,117	10,193
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		18,591,656	23,566,550	27,879,178	32,308,498	36,856,940	38,537,519	40,258,094	42,019,457	43,822,415	45,667,789	47,556,418	49,489,151	51,466,857	53,490,419	55,560,735	56,505,268	57,465,857	58,442,777
(B) SMALL COMMERCIAL (A)		4,111,043	4,212,076	4,313,109	4,773,129	5,956,766	6,004,269	6,051,772	6,099,274	6,992,499	9,578,980	9,622,317	9,665,654	9,708,991	9,752,328	9,798,900	9,965,481	10,134,894	10,307,187
(C) MEDIUM COMMERCIAL (AL-TOU)		52,827,615	53,433,812	54,040,008	63,357,636	92,311,842	100,779,730	109,247,618	117,715,506	131,257,727	157,608,048	164,592,842	171,577,636	178,562,430	185,547,224	195,457,126	198,779,897	202,159,155	205,595,861
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		12,333,130	12,636,229	12,939,327	14,319,387	17,870,299	18,012,807	18,155,315	18,297,823	26,017,762	58,293,796	58,423,808	58,553,819	58,683,831	62,542,446	73,867,972	75,123,728	76,400,831	77,699,646
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS		87,863,444	93,848,667	99,171,623	114,758,650	152,995,847	163,334,325	173,712,799	184,132,061	208,090,402	271,148,613	280,195,384	289,286,261	298,422,109	311,332,418	334,684,733	340,374,374	346,160,738	352,045,471
III. ESTIMATED SDG&E RATES ($/KWH):																			
(A) RESIDENTIAL		$0.157	$0.155	$0.144	$0.146	$0.147	$0.141	$0.143	$0.146	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.167	$0.171	$0.171	$0.166
(B) SMALL COMMERCIAL (A)		$0.179	$0.177	$0.165	$0.167	$0.169	$0.162	$0.165	$0.168	$0.171	$0.174	$0.178	$0.181	$0.185	$0.189	$0.192	$0.196	$0.196	$0.192
(C) MEDIUM COMMERCIAL (AL-TOU)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
(E) AGRICULTURAL		$0.167	$0.165	$0.164	$0.165	$0.167	$0.160	$0.163	$0.166	$0.169	$0.172	$0.175	$0.179	$0.182	$0.185	$0.189	$0.192	$0.192	$0.188
(F) STREET LIGHTING AND TRAFFIC CONTROL		$0.111	$0.109	$0.108	$0.109	$0.110	$0.106	$0.108	$0.110	$0.112	$0.114	$0.116	$0.118	$0.120	$0.122	$0.124	$0.127	$0.127	$0.123
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
(A) RESIDENTIAL		2,914,995	3,651,137	4,013,350	4,701,460	5,415,985	5,423,090	5,767,630	6,141,410	6,523,946	6,931,097	7,360,201	7,810,688	8,283,539	8,779,780	9,300,480	9,646,429	9,810,418	9,729,664
(B) SMALL COMMERCIAL (A)		737,544	746,720	713,407	798,179	1,005,866	971,081	996,578	1,024,584	1,196,616	1,671,198	1,711,875	1,753,548	1,796,243	1,839,985	1,885,422	1,955,535	1,988,779	1,978,933
(C) MEDIUM COMMERCIAL (AL-TOU)		7,540,950	7,536,737	7,544,470	8,934,206	13,136,967	13,771,488	15,179,424	16,665,552	18,904,410	23,113,789	24,585,611	26,105,197	27,673,970	29,293,396	31,435,429	32,569,542	33,123,224	32,815,528
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		1,760,510	1,782,316	1,806,446	2,019,210	2,543,136	2,461,439	2,522,593	2,590,511	3,747,211	8,548,995	8,726,899	8,908,848	9,094,940	9,873,932	11,880,209	12,308,817	12,518,067	12,401,781
(E) AGRICULTURAL		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(F) STREET LIGHTING AND TRAFFIC CONTROL		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL REVENUE REQUIREMENT		$12,953,999	$13,716,910	$14,077,672	$16,453,055	$22,101,954	$22,627,097	$24,466,225	$26,422,057	$30,372,184	$40,265,079	$42,384,586	$44,578,281	$46,848,693	$49,787,093	$54,501,540	$56,480,323	$57,440,488	$56,925,906
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$106,014	$247,721	$449,810	$1,166,805	$2,632,340	$3,148,571	$3,686,239	$3,861,071	$5,013,681	$7,627,613	$8,028,881	$8,465,500	$8,358,252	$9,271,918	$10,775,418	$10,929,413	$11,658,941	$11,928,421
(ii) CONTRACT PURCHASES		$455,520	$446,760	$455,520	$455,520	$911,040	$928,560	$946,080	$1,419,120	$1,419,120	$2,365,200	$2,321,400	$2,321,400	$3,372,600	$3,372,600	$3,372,600	$4,064,640	$4,064,640	$4,064,640
(iii) POWER PRODUCTION		$4,915,469	$4,785,667	$4,891,131	$4,915,469	$4,915,469	$4,972,257	$5,037,158	$5,012,820	$5,029,046	$5,029,046	$4,964,145	$4,923,581	$5,045,271	$5,126,397	$5,183,186	$5,296,763	$5,450,903	$5,410,340
(iv) DWR POWER		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) TRANSMISSION AND SCHEDULING	$0.00314	$276,316	$305,003	$337,364	$448,911	$745,437	$824,612	$905,403	$1,010,124	$1,195,961	$1,757,780	$1,855,213	$1,954,819	$2,056,651	$2,196,125	$2,438,138	$2,513,955	$2,592,046	$2,672,479
(vi) DISTRIBUTION		$1,290,452	$1,569,829	$1,802,855	$2,045,992	$2,310,514	$2,380,062	$2,449,610	$2,519,158	$2,605,200	$2,725,794	$2,794,557	$2,863,321	$2,932,084	$3,000,946	$3,071,472	$3,094,149	$3,116,901	$3,139,728
(vii) CALIFORNIA ISO COSTS		$112,491	$130,313	$152,153	$223,626	$415,094	$474,357	$536,948	$620,065	$758,361	$1,169,049	$1,262,756	$1,361,389	$1,466,126	$1,602,907	$1,824,113	$1,921,933	$2,025,047	$2,131,683
(viii) ANCILLARY SERVICES & CAPACITY RESERVES		$141,956	$153,460	$171,846	$215,501	$320,245	$353,259	$387,865	$414,930	$483,684	$660,167	$675,423	$694,013	$739,683	$790,429	$868,193	$907,002	$955,043	$964,908
SUBTOTAL - POWER SUPPLY AND DELIVERY		$7,298,218	$7,638,752	$8,260,679	$9,471,824	$12,250,139	$13,081,678	$13,949,303	$14,857,288	$16,505,052	$21,334,650	$21,902,375	$22,584,023	$23,970,668	$25,361,322	$27,533,121	$28,727,854	$29,863,520	$30,312,197
(B) UTILITY OPERATIONS:																			
(i) DISTRIBUTION O&M		$492,856	$622,514	$738,393	$864,138	$1,005,382	$1,062,758	$1,122,375	$1,184,309	$1,256,873	$1,350,005	$1,419,822	$1,492,287	$1,567,488	$1,645,571	$1,727,543	$1,784,189	$1,842,633	$1,902,931
(ii) CUSTOMER SERVICE		$162,107	$204,753	$242,867	$284,227	$330,684	$349,556	$369,165	$389,535	$413,402	$444,035	$466,999	$490,834	$515,568	$541,251	$568,212	$586,844	$606,067	$625,900
(iii) ADMINSTRATIVE & GENERAL		$542,123	$684,742	$812,204	$950,520	$1,105,882	$1,168,994	$1,234,571	$1,302,696	$1,382,513	$1,484,955	$1,561,752	$1,641,460	$1,724,178	$1,810,067	$1,900,232	$1,962,541	$2,026,827	$2,093,152
SUBTOTAL - UTILITY OPERATIONS		$1,197,085	$1,512,009	$1,793,464	$2,098,885	$2,441,947	$2,581,308	$2,726,111	$2,876,540	$3,052,788	$3,278,995	$3,448,573	$3,624,580	$3,807,233	$3,996,889	$4,195,987	$4,333,574	$4,475,527	$4,621,983
(C) PUBLIC PURPOSE PROGRAMS		$466,343	$498,125	$522,592	$604,546	$775,854	$830,019	$890,238	$946,712	$1,045,325	$1,320,408	$1,360,249	$1,405,765	$1,484,738	$1,566,492	$1,691,665	$1,757,574	$1,820,970	$1,782,301
(D) FRANCHISE FEES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(E) PROPERTY TAXES		$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331
(F) NON-BYPASSABLE CHARGES		$717,962	$612,292	$473,317	$529,283	$709,128	$734,104	$756,223	$815,331	$888,523	$1,148,436	$1,186,753	$1,225,257	$1,263,951	$1,318,632	$1,417,540	$1,441,638	$1,466,146	$0
(G) OTHER "PASS-THROUGH" COSTS		$583,031	$709,700	$466,051	$637,817	$982,709	$1,139,681	$1,386,839	$1,471,301	$1,672,970	$2,212,116	$2,284,468	$2,357,076	$2,429,946	$2,535,011	$2,729,371	$2,775,770	$2,822,959	$2,870,949
TOTAL - OPERATING EXPENSES		$10,391,969	$11,100,208	$11,645,435	$13,471,685	$17,289,107	$18,496,121	$19,838,045	$21,096,502	$23,293,988	$29,423,935	$30,311,747	$31,326,032	$33,085,866	$34,907,678	$37,697,015	$39,165,741	$40,578,452	$39,716,761
(H) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$932,163	$768,324	$712,215	$595,383	$402,368	$326,289	$248,201	$270,732	$92,399	$0	$0	$0	$0	$0	$0	$0	$0	$0
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$932,163	$768,324	$712,215	$595,383	$402,368	$326,289	$248,201	$270,732	$92,399	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL EXPENSES NET OF MARKET REVENUES		$9,459,806	$10,331,884	$10,933,220	$12,876,302	$16,886,739	$18,169,832	$19,589,844	$20,825,770	$23,201,589	$29,423,935	$30,311,747	$31,326,032	$33,085,866	$34,907,678	$37,697,015	$39,165,741	$40,578,452	$39,716,761
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$12,953,999	$13,716,910	$14,077,672	$16,453,055	$22,101,954	$22,627,097	$24,466,225	$26,422,057	$30,372,184	$40,265,079	$42,384,586	$44,578,281	$46,848,693	$49,787,093	$54,501,540	$56,480,323	$57,440,488	$56,925,906
(B) CHULA VISTA REVENUE REQUIREMENT		$9,459,806	$10,331,884	$10,933,220	$12,876,302	$16,886,739	$18,169,832	$19,589,844	$20,825,770	$23,201,589	$29,423,935	$30,311,747	$31,326,032	$33,085,866	$34,907,678	$37,697,015	$39,165,741	$40,578,452	$39,716,761
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	$54,044,323	$3,494,193	$3,385,026	$3,144,452	$3,576,753	$5,215,215	$4,457,265	$4,876,381	$5,596,287	$7,170,595	$10,841,145	$12,072,839	$13,252,250	$13,762,827	$14,879,416	$16,804,526	$17,314,581	$16,862,036	$17,209,145
(D) BENEFITS	26.1%	27.0%	24.7%	22.3%	21.7%	23.6%	19.7%	19.9%	21.2%	23.6%	26.9%	28.5%	29.7%	29.4%	29.9%	30.8%	30.7%	29.4%	30.2%
NPV 2006-2023	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
NPV 2006-2014	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!									
NPV 2015-2023	#REF!	0	0	0	0	0	0	0	0	0	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME
GREENFIELD OPTION - CONTRACTS

CATEGORY	NAP	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		3,706	4,632	5,404	6,176	6,948	7,164	7,380	7,596	7,812	8,028	8,244	8,460	8,676	8,892	9,108	9,169	9,230	9,291
(B) SMALL COMMERCIAL (A)		225	230	236	261	326	328	331	333	382	524	526	528	531	533	536	545	554	563
(C) MEDIUM COMMERCIAL (AL-TOU)		85	86	87	102	149	163	176	190	212	254	265	277	288	299	315	321	326	332
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		1	1	1	1	2	2	2	2	2	5	5	5	5	6	7	7	7	7
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS		4,017	4,950	5,728	6,540	7,424	7,656	7,888	8,120	8,408	8,811	9,040	9,270	9,499	9,729	9,965	10,041	10,117	10,193
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		18,591,656	23,566,550	27,879,178	32,308,498	36,856,940	38,537,519	40,258,094	42,019,457	43,822,415	45,667,789	47,556,418	49,489,151	51,466,857	53,490,419	55,560,735	56,505,268	57,465,857	58,442,777
(B) SMALL COMMERCIAL (A)		4,111,043	4,212,076	4,313,109	4,773,129	5,956,766	6,004,269	6,051,772	6,099,274	6,992,499	9,578,980	9,622,317	9,665,654	9,708,991	9,752,328	9,798,900	9,965,481	10,134,894	10,307,187
(C) MEDIUM COMMERCIAL (AL-TOU)		52,827,615	53,433,812	54,040,008	63,357,636	92,311,842	100,779,730	109,247,618	117,715,506	131,257,727	157,608,048	164,592,842	171,577,636	178,562,430	185,547,224	195,457,126	198,779,897	202,159,155	205,595,861
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		12,333,130	12,636,229	12,939,327	14,319,387	17,870,299	18,012,807	18,155,315	18,297,823	26,017,762	58,293,796	58,423,808	58,553,819	58,683,831	62,542,446	73,867,972	75,123,728	76,400,831	77,699,646
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS		87,863,444	93,848,667	99,171,623	114,758,650	152,995,847	163,334,325	173,712,799	184,132,061	208,090,402	271,148,613	280,195,384	289,286,261	298,422,109	311,332,418	334,684,733	340,374,374	346,160,738	352,045,471
III. ESTIMATED SDG&E RATES ($/KWH):																			
(A) RESIDENTIAL		$0.157	$0.155	$0.144	$0.146	$0.147	$0.141	$0.143	$0.146	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.167	$0.171	$0.171	$0.166
(B) SMALL COMMERCIAL (A)		$0.179	$0.177	$0.165	$0.167	$0.169	$0.162	$0.165	$0.168	$0.171	$0.174	$0.178	$0.181	$0.185	$0.189	$0.192	$0.196	$0.196	$0.192
(C) MEDIUM COMMERCIAL (AL-TOU)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.143	$0.141	$0.140	$0.141	$0.142	$0.137	$0.139	$0.142	$0.144	$0.147	$0.149	$0.152	$0.155	$0.158	$0.161	$0.164	$0.164	$0.160
(E) AGRICULTURAL		$0.167	$0.165	$0.164	$0.165	$0.167	$0.160	$0.163	$0.166	$0.169	$0.172	$0.175	$0.179	$0.182	$0.185	$0.189	$0.192	$0.192	$0.188
(F) STREET LIGHTING AND TRAFFIC CONTROL		$0.111	$0.109	$0.108	$0.109	$0.110	$0.106	$0.108	$0.110	$0.112	$0.114	$0.116	$0.118	$0.120	$0.122	$0.124	$0.127	$0.127	$0.123
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
(A) RESIDENTIAL		2,914,995	3,651,137	4,013,350	4,701,460	5,415,985	5,423,090	5,767,630	6,141,410	6,523,946	6,931,097	7,360,201	7,810,688	8,283,539	8,779,780	9,300,480	9,646,429	9,810,418	9,729,664
(B) SMALL COMMERCIAL (A)		737,544	746,720	713,407	798,179	1,005,866	971,081	996,578	1,024,584	1,196,616	1,671,198	1,711,875	1,753,548	1,796,243	1,839,985	1,885,422	1,955,535	1,988,779	1,978,933
(C) MEDIUM COMMERCIAL (AL-TOU)		7,540,950	7,536,737	7,544,470	8,934,206	13,136,967	13,771,488	15,179,424	16,665,552	18,904,410	23,113,789	24,585,611	26,105,197	27,673,970	29,293,396	31,435,429	32,569,542	33,123,224	32,815,528
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		1,760,510	1,782,316	1,806,446	2,019,210	2,543,136	2,461,439	2,522,593	2,590,511	3,747,211	8,548,995	8,726,899	8,908,848	9,094,940	9,873,932	11,880,209	12,308,817	12,518,067	12,401,781
(E) AGRICULTURAL		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(F) STREET LIGHTING AND TRAFFIC CONTROL		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL REVENUE REQUIREMENT		$12,953,999	$13,716,910	$14,077,672	$16,453,055	$22,101,954	$22,627,097	$24,466,225	$26,422,057	$30,372,184	$40,265,079	$42,384,586	$44,578,281	$46,848,693	$49,787,093	$54,501,540	$56,480,323	$57,440,488	$56,925,906
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$92,684	$182,513	$307,231	$1,009,841	$0	$58,602	$149,238	$223,143	$1,047,300	$313,988	$526,959	$793,209	$618,609	$1,100,444	$713,511	$718,072	$911,985	$1,121,930
(ii) CONTRACT PURCHASES		$5,594,200	$5,585,440	$5,594,200	$5,594,200	$10,731,840	$10,749,360	$10,766,880	$11,239,920	$11,239,920	$16,801,400	$16,757,600	$16,757,600	$17,808,800	$17,808,800	$21,075,400	$21,767,440	$21,767,440	$21,767,440
(iii) POWER PRODUCTION		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(iv) DWR POWER	Scheduling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) TRANSMISSION AND SCHEDULING	Outsourced	$2,079,063	$2,183,057	$2,281,209	$2,569,553	$3,508,617	$3,582,623	$3,631,346	$3,732,328	$3,890,271	$4,580,228	$4,651,729	$4,730,986	$4,866,803	$4,975,906	$5,305,814	$5,409,270	$5,472,798	$5,542,093
(vi) DISTRIBUTION		$1,290,452	$1,569,829	$1,802,855	$2,045,992	$2,310,514	$2,380,062	$2,449,610	$2,519,158	$2,605,200	$2,725,794	$2,794,557	$2,863,321	$2,932,084	$3,000,946	$3,071,472	$3,094,149	$3,116,901	$3,139,728
(vii) CALIFORNIA ISO COSTS		$481,804	$508,780	$538,477	$623,631	$1,006,370	$1,049,685	$1,096,952	$1,185,802	$1,310,982	$1,833,103	$1,915,838	$2,007,764	$2,151,752	$2,273,766	$2,582,064	$2,716,744	$2,820,070	$2,928,991
(viii) ANCILLARY SERVICES & CAPACITY RESERVES		$196,440	$203,381	$220,405	$256,540	$342,136	$370,190	$399,699	$421,355	$477,848	$622,068	$633,305	$647,727	$687,354	$730,360	$794,984	$828,851	$871,030	$878,323
SUBTOTAL - POWER SUPPLY AND DELIVERY		$9,734,644	$10,233,000	$10,744,376	$12,099,757	$17,899,476	$18,190,523	$18,493,724	$19,321,706	$20,571,521	$26,876,580	$27,279,988	$27,800,607	$29,065,402	$29,890,223	$33,543,246	$34,534,526	$34,960,224	$35,378,504
(B) UTILITY OPERATIONS:																			
(i) DISTRIBUTION O&M		$901,681	$1,016,866	$1,119,316	$1,184,667	$1,161,130	$1,213,074	$1,281,123	$1,351,817	$1,434,644	$1,540,948	$1,620,641	$1,703,355	$1,789,191	$1,878,319	$1,971,885	$2,036,543	$2,103,253	$2,172,080
(ii) CUSTOMER SERVICE		$364,499	$411,061	$452,476	$478,894	$469,379	$493,693	$521,387	$550,158	$583,867	$627,130	$659,563	$693,226	$728,159	$764,432	$802,511	$828,826	$855,975	$883,986
(iii) ADMINISTRATIVE & GENERAL		$652,271	$735,595	$809,707	$856,982	$839,955	$874,541	$923,601	$974,566	$1,034,278	$1,110,916	$1,168,369	$1,228,000	$1,289,882	$1,354,137	$1,421,591	$1,468,205	$1,516,299	$1,565,918
SUBTOTAL - UTILITY OPERATIONS		$1,918,451	$2,163,523	$2,381,499	$2,520,543	$2,470,464	$2,581,308	$2,726,111	$2,876,541	$3,052,788	$3,278,995	$3,448,573	$3,624,580	$3,807,233	$3,996,888	$4,195,987	$4,333,574	$4,475,527	$4,621,983
		$478	$437	$416	$385	$333	$337	$346	$354	$363	$372	$381	$391	$401	$411	$421	$432	$442	$453
(C) PUBLIC PURPOSE PROGRAMS		$614,707	$650,623	$666,914	$747,827	$1,042,620	$1,070,051	$1,103,752	$1,156,467	$1,236,382	$1,580,788	$1,612,909	$1,650,859	$1,724,108	$1,779,277	$1,974,043	$2,030,393	$2,060,432	$2,020,335
(D) FRANCHISE FEES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(E) PROPERTY TAXES		$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331	$129,331
(F) NON-BYPASSABLE CHARGES		$717,962	$612,292	$473,317	$529,283	$709,128	$734,104	$756,223	$815,331	$888,523	$1,148,436	$1,186,753	$1,225,257	$1,263,951	$1,318,632	$1,417,540	$1,441,638	$1,466,146	$0
(G) OTHER "PASS-THROUGH" COSTS		$583,031	$709,700	$466,051	$637,817	$982,709	$1,139,681	$1,386,839	$1,471,301	$1,672,970	$2,212,116	$2,284,468	$2,357,076	$2,429,946	$2,535,011	$2,729,371	$2,775,770	$2,822,959	$2,870,949
TOTAL - OPERATING EXPENSES		$13,698,126	$14,498,468	$14,861,488	$16,664,558	$23,233,728	$23,844,998	$24,595,981	$25,770,675	$27,551,515	$35,226,246	$35,942,020	$36,787,710	$38,419,970	$39,649,362	$43,989,517	$45,245,233	$45,914,618	$45,021,103
(H) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$444,506	$256,365	$130,359	$0	$1,267,597	$886,285	$516,337	$446,893	$33,074	$628,698	$396,431	$211,751	$331,946	$121,879	$484,237	$574,292	$446,900	$330,059
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$444,506	$256,365	$130,359	$0	$1,267,597	$886,285	$516,337	$446,893	$33,074	$628,698	$396,431	$211,751	$331,946	$121,879	$484,237	$574,292	$446,900	$330,059
TOTAL EXPENSES NET OF MARKET REVENUES		$13,253,620	$14,242,104	$14,731,130	$16,664,558	$21,966,131	$22,958,714	$24,079,643	$25,323,783	$27,518,441	$34,597,547	$35,545,589	$36,575,959	$38,088,024	$39,527,483	$43,505,280	$44,670,941	$45,467,718	$44,691,043
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$12,953,999	$13,716,910	$14,077,672	$16,453,055	$22,101,954	$22,627,097	$24,466,225	$26,422,057	$30,372,184	$40,265,079	$42,384,586	$44,578,281	$46,848,693	$49,787,093	$54,501,540	$56,480,323	$57,440,488	$56,925,906
(B) CHULA VISTA REVENUE REQUIREMENT		$13,253,620	$14,242,104	$14,731,130	$16,664,558	$21,966,131	$22,958,714	$24,079,643	$25,323,783	$27,518,441	$34,597,547	$35,545,589	$36,575,959	$38,088,024	$39,527,483	$43,505,280	$44,670,941	$45,467,718	$44,691,043
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	$20,563,008	($299,621)	($525,193)	($653,457)	($211,502)	$135,823	($331,616)	$386,582	$1,098,275	$2,853,743	$5,667,532	$6,838,997	$8,002,322	$8,760,669	$10,259,610	$10,996,260	$11,809,382	$11,972,770	$12,234,863
(D) BENEFITS	9.9%	-2.3%	-3.8%	-4.6%	-1.3%	0.6%	-1.5%	1.6%	4.2%	9.4%	14.1%	16.1%	18.0%	18.7%	20.6%	20.2%	20.9%	20.8%	21.5%
NPV 2006-2023	$20,563,005	($299,621)	($525,193)	($653,457)	($211,502)	$135,823	($331,616)	$386,582	$1,098,275	$2,853,743	$5,667,532	$6,838,997	$8,002,322	$8,760,669	$10,259,610	$10,996,260	$11,809,382	$11,972,770	$12,234,863
NPV 2006-2014	$433,004	($299,621)	($525,193)	($653,457)	($211,502)	$135,823	($331,616)	$386,582	$1,098,275	$2,853,743									
NPV 2015-2023	$20,130,001	0	0	0	0	0	0	0	0	0	$5,667,532	$6,838,997	$8,002,322	$8,760,669	$10,259,610	$10,996,260	$11,809,382	$11,972,770	$12,234,863
		$478	$437	$416	$385	$333	$337	$346	$354	$363	$372	$381	$391	$401	$411	$421	$432	$442	$453
		4,017	4,950	5,728	6,540	7,424	7,656	7,888	8,120	8,408	8,811	9,040	9,270	9,499	9,729	9,965	10,041	10,117	10,193
	O&M Adjust Cells	0.728125	0.6501109	0.6033063	0.5456144	0.459645	0.7021031	0.7021033	0.7021033	0.7021032	0.7021031	0.7021031	0.7021031	0.7021031	0.7021031	0.7021031	0.7021032	0.7021032	0.7021032
Escalation Rate for Derived O&M Amounts			-8.5%	-4.9%	-7.3%	-13.7%	1.3%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME
CCA OPTION - CONTRACTS

CATEGORY	NPV	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		74,440	76,940	79,022	81,105	83,187	83,770	84,353	84,935	85,518	86,101	86,684	87,267	87,850	88,432	89,015	89,180	89,345	89,510
(B) SMALL COMMERCIAL (A)		3,450	3,495	3,540	3,605	3,689	3,710	3,731	3,753	3,820	3,991	4,024	4,056	4,089	4,122	4,154	4,193	4,232	4,272
(C) MEDIUM COMMERCIAL (AL-TOU)		413	418	423	442	491	506	522	537	561	606	621	635	649	664	683	691	700	708
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		14	15	15	15	15	16	16	16	16	19	20	20	20	20	21	22	22	22
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		4,162	4,267	4,375	4,485	4,172	4,277	4,385	4,496	4,609	4,649	4,689	4,730	4,770	4,812	4,851	4,891	4,931	9,956
SUBTOTAL - CUSTOMER ACCOUNTS		82,479	85,134	87,375	89,652	91,554	92,279	93,006	93,737	94,525	95,367	96,037	96,708	97,379	98,051	98,725	98,977	99,230	104,469
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		373,441,677	391,414,163	407,663,619	424,292,848	441,309,320	450,654,032	460,174,341	469,873,338	479,754,166	489,820,022	500,074,156	510,519,875	521,160,540	531,999,567	543,040,434	551,486,365	560,062,938	568,772,167
(B) SMALL COMMERCIAL (A)		63,115,857	63,935,426	64,763,744	65,959,906	67,482,251	67,870,336	68,260,307	68,652,173	69,891,668	73,021,464	73,612,809	74,208,888	74,809,742	75,415,411	76,001,183	76,711,393	77,428,899	78,153,786
(C) MEDIUM COMMERCIAL (AL-TOU)		255,962,359	259,042,244	262,152,252	274,004,181	304,124,450	313,764,856	323,411,752	333,065,175	347,799,493	376,020,275	384,891,687	393,779,394	402,683,539	411,604,263	423,370,462	428,564,773	433,830,939	439,170,047
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		162,345,060	164,474,940	166,627,065	169,878,669	174,290,700	175,299,094	176,312,282	177,330,290	185,930,574	219,587,916	221,111,166	222,646,450	224,193,873	229,482,144	242,178,517	244,816,376	247,486,932	250,190,642
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		7,321,167	7,505,737	7,694,960	7,888,953	7,338,790	7,523,804	7,713,482	7,907,942	8,107,305	8,177,335	8,247,970	8,319,214	8,391,075	8,463,556	8,533,055	8,603,126	8,673,771	8,744,997
SUBTOTAL - LOAD REQUIREMENTS		862,186,120	886,372,509	908,901,639	942,024,556	994,545,510	1,015,112,122	1,035,872,164	1,056,828,918	1,091,483,206	1,166,627,011	1,187,937,787	1,209,473,823	1,231,238,769	1,256,964,942	1,293,123,651	1,310,182,032	1,327,483,480	1,345,031,639
III. ESTIMATED SDG&E RATES ($/KWH):																			
(A) RESIDENTIAL		$0.075	$0.073	$0.071	$0.071	$0.072	$0.066	$0.067	$0.069	$0.070	$0.072	$0.073	$0.075	$0.077	$0.079	$0.081	$0.082	$0.082	$0.078
(B) SMALL COMMERCIAL (A)		$0.095	$0.092	$0.089	$0.090	$0.090	$0.083	$0.084	$0.087	$0.088	$0.091	$0.093	$0.095	$0.097	$0.099	$0.102	$0.104	$0.104	$0.100
(C) MEDIUM COMMERCIAL (AL-TOU)		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.099
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.099
(E) AGRICULTURAL		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.098
(F) STREET LIGHTING AND TRAFFIC CONTROL		$0.086	$0.084	$0.081	$0.082	$0.082	$0.075	$0.077	$0.079	$0.080	$0.082	$0.084	$0.086	$0.088	$0.090	$0.092	$0.095	$0.095	$0.090
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
(A) RESIDENTIAL		28,120,628	28,554,155	28,878,174	30,277,572	31,679,837	29,604,463	30,839,911	32,261,113	33,634,063	35,129,087	36,708,158	38,357,747	40,080,976	41,881,108	43,761,546	45,494,830	46,202,354	44,511,816
(B) SMALL COMMERCIAL (A)		5,990,652	5,878,012	5,779,565	5,933,270	6,106,529	5,615,510	5,766,157	5,941,896	6,181,619	6,609,587	6,821,896	7,041,207	7,267,753	7,501,773	7,740,994	8,000,542	8,075,374	7,819,959
(C) MEDIUM COMMERCIAL (AL-TOU)		23,941,453	23,469,440	23,055,211	24,288,944	27,120,223	25,584,180	26,922,364	28,407,732	30,312,579	33,538,386	35,147,141	36,816,012	38,547,070	40,342,453	42,488,253	44,039,398	44,580,551	43,269,117
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		15,184,954	14,901,564	14,654,164	15,058,798	15,542,330	14,293,773	14,677,090	15,124,822	16,204,840	19,585,711	20,191,201	20,816,108	21,461,063	22,492,169	24,304,346	25,157,378	25,431,805	24,649,969
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
(F) STREET LIGHTING AND TRAFFIC CONTROL		631,448	627,095	624,141	644,830	603,446	565,846	592,096	621,929	651,369	672,266	694,151	716,770	740,147	764,308	788,945	814,398	821,086	790,789
TOTAL REVENUE REQUIREMENT		$73,869,135	$73,430,266	$72,991,255	$76,203,413	$81,052,365	$75,663,773	$78,797,618	$82,357,492	$86,984,471	$95,535,036	$99,562,547	$103,747,844	$108,097,009	$112,981,810	$119,084,083	$123,506,547	$125,111,169	$121,041,650
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$2,802,774	$3,423,630	$3,847,307	$5,183,837	$7,270,636	$7,672,202	$8,107,973	$8,828,611	$9,976,579	$12,969,913	$665,704	$691,528	$808,689	$1,172,401	$1,859,978	$2,173,370	$2,791,605	$3,288,316
(ii) CONTRACT PURCHASES		$47,094,240	$47,479,680	$48,460,800	$48,916,320	$49,827,360	$52,506,600	$53,584,080	$54,057,120	$55,003,200	$56,422,320	$76,053,200	$77,446,040	$78,418,400	$78,418,400	$78,418,400	$84,852,600	$84,852,600	$84,852,600
(iii) POWER PRODUCTION		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(iv) DWR POWER		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) OPERATIONS AND SCHEDULING		$4,155,465	$4,215,931	$4,272,254	$4,355,061	$4,486,364	$4,537,780	$4,589,680	$4,642,072	$4,728,708	$4,916,568	$4,969,844	$5,023,685	$5,078,097	$5,142,412	$5,232,809	$5,275,455	$5,318,709	$5,362,579
(vi) ANCILLARY SERVICES & CAPACITY RESERVES		$1,923,853	$1,917,335	$2,016,453	$2,102,070	$2,219,529	$2,295,830	$2,378,226	$2,412,909	$2,501,353	$2,673,255	$2,681,627	$2,704,521	$2,832,045	$2,944,842	$3,068,063	$3,186,789	$3,336,472	$3,352,051
(vi) CALIFORNIA ISO COSTS		$2,020,692	$2,123,389	$2,238,047	$2,380,046	$2,581,387	$2,709,532	$2,843,763	$2,980,689	$3,164,490	$3,476,403	$3,849,974	$4,029,800	$4,193,883	$4,357,310	$4,548,619	$4,730,832	$4,911,499	$5,088,668
SUBTOTAL - POWER SUPPLY		$57,997,024	$59,159,964	$60,834,862	$62,937,335	$66,385,276	$69,721,945	$71,503,722	$72,921,401	$75,374,329	$80,458,458	$88,220,349	$89,895,573	$91,331,114	$92,035,365	$93,127,869	$100,219,047	$101,210,885	$101,944,214
(B) NON-BYPASSABLE CHARGES		$9,827,793	$9,148,056	$7,773,360	$8,658,598	$9,906,016	$10,477,193	$11,493,997	$11,802,461	$12,030,928	$12,883,159	$13,114,302	$13,347,659	$13,583,264	$13,866,451	$14,275,816	$14,460,466	$14,647,717	$9,140,796
TOTAL - OPERATING EXPENSES		$67,824,817	$68,308,020	$68,608,221	$71,595,932	$76,291,291	$80,199,138	$82,997,719	$84,723,862	$87,405,257	$93,341,617	$101,334,652	$103,243,232	$104,914,378	$105,901,816	$107,403,685	$114,679,512	$115,858,601	$111,085,011
(C) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$299,001	$145,396	$96,855	$10,577	$0	$0	$0	$0	$0	$0	$4,196,997	$4,235,255	$3,815,499	$3,014,152	$1,946,781	$1,763,693	$1,413,627	$1,026,658
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$299,001	$145,396	$96,855	$10,577	$0	$0	$0	$0	$0	$0	$4,196,997	$4,235,255	$3,815,499	$3,014,152	$1,946,781	$1,763,693	$1,413,627	$1,026,658
TOTAL EXPENSES NET OF MARKET REVENUES		$67,525,816	$68,162,624	$68,511,366	$71,585,355	$76,291,291	$80,199,138	$82,997,719	$84,723,862	$87,405,257	$93,341,617	$97,137,654	$99,007,977	$101,098,879	$102,887,664	$105,456,904	$112,915,820	$114,444,974	$110,058,352
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$73,869,135	$73,430,266	$72,991,255	$76,203,413	$81,052,365	$75,663,773	$78,797,618	$82,357,492	$86,984,471	$95,535,036	$99,562,547	$103,747,844	$108,097,009	$112,981,810	$119,084,083	$123,506,547	$125,111,169	$121,041,650
(B) CHULA VISTA REVENUE REQUIREMENT		$67,525,816	$68,162,624	$68,511,366	$71,585,355	$76,291,291	$80,199,138	$82,997,719	$84,723,862	$87,405,257	$93,341,617	$97,137,654	$99,007,977	$101,098,879	$102,887,664	$105,456,904	$112,915,820	$114,444,974	$110,058,352
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	$28,311,244	$6,343,320	$5,267,642	$4,479,889	$4,618,059	$4,761,073	($4,535,365)	($4,200,101)	($2,366,370)	($420,786)	$2,193,419	$2,424,892	$4,739,867	$6,998,130	$10,094,145	$13,627,179	$10,590,727	$10,666,195	$10,983,298
(D) BENEFITS (% OF GENERATION RATES)	4.4%	8.6%	7.2%	6.1%	6.1%	5.9%	-6.0%	-5.3%	-2.9%	-0.5%	2.3%	2.4%	4.6%	6.5%	8.9%	11.4%	8.6%	8.5%	9.1%
(E) BENEFITS (% OF TOTAL RATES)	2.4%	4.9%	4.0%	3.4%	3.4%	3.3%	-3.2%	-2.8%	-1.5%	-0.3%	1.3%	1.3%	2.5%	3.6%	5.0%	6.4%	4.8%	4.8%	5.0%
NPV 2006-2023	$28,311,244	$6,343,320	$5,267,642	$4,479,889	$4,618,059	$4,761,073	($4,535,365)	($4,200,101)	($2,366,370)	($420,786)	$2,193,419	$2,424,892	$4,739,867	$6,998,130	$10,094,145	$13,627,179	$10,590,727	$10,666,195	$10,983,298
NPV 2006-2014	$12,362,307	$6,343,320	$5,267,642	$4,479,889	$4,618,059	$4,761,073	($4,535,365)	($4,200,101)	($2,366,370)	($420,786)									
NPV 2015-2023	$15,948,937	0	0	0	0	0	0	0	0	0	$2,193,419	$2,424,892	$4,739,867	$6,998,130	$10,094,145	$13,627,179	$10,590,727	$10,666,195	$10,983,298

CITY OF CHULA VISTA
FINANCIAL PRO FORMA ANALYSIS
CONSOLIDATED STATEMENT OF INCOME
CCA OPTION - GENERATION

CATEGORY	NPV	[3] 2006	[4] 2007	[5] 2008	[6] 2009	[7] 2010	[8] 2011	[9] 2012	[10] 2013	[11] 2014	[12] 2015	[13] 2016	[14] 2017	[15] 2018	[16] 2019	[17] 2020	[18] 2021	[19] 2022	[20] 2023
I. CUSTOMER ACCOUNTS:																			
(A) RESIDENTIAL		74,440	76,940	79,022	81,105	83,187	83,770	84,353	84,935	85,518	86,101	86,684	87,267	87,850	88,432	89,015	89,180	89,345	89,510
(B) SMALL COMMERCIAL (A)		3,450	3,495	3,540	3,605	3,689	3,710	3,731	3,753	3,820	3,991	4,024	4,056	4,089	4,122	4,154	4,193	4,232	4,272
(C) MEDIUM COMMERCIAL (AL-TOU)		413	418	423	442	491	506	522	537	561	606	621	635	649	664	683	691	700	708
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		14	15	15	15	15	16	16	16	16	19	20	20	20	20	21	22	22	22
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		4,162	4,267	4,375	4,485	4,172	4,277	4,385	4,496	4,609	4,649	4,689	4,730	4,770	4,812	4,851	4,891	4,931	9,956
SUBTOTAL - CUSTOMER ACCOUNTS		82,479	85,134	87,375	89,652	91,554	92,279	93,006	93,737	94,525	95,367	96,037	96,708	97,379	98,051	98,725	98,977	99,230	104,469
II. LOAD REQUIREMENTS (KWH):																			
(A) RESIDENTIAL		373,441,677	391,414,163	407,663,619	424,292,848	441,309,320	450,654,032	460,174,341	469,873,338	479,754,166	489,820,022	500,074,156	510,519,875	521,160,540	531,999,567	543,040,434	551,486,365	560,062,938	568,772,167
(B) SMALL COMMERCIAL (A)		63,115,857	63,935,426	64,763,744	65,959,906	67,482,251	67,870,336	68,260,307	68,652,173	69,891,668	73,021,464	73,612,809	74,208,888	74,809,742	75,415,411	76,001,183	76,711,393	77,428,899	78,153,786
(C) MEDIUM COMMERCIAL (AL-TOU)		255,962,359	259,042,244	262,152,252	274,004,181	304,124,450	313,764,856	323,411,752	333,065,175	347,799,493	376,020,275	384,891,687	393,779,394	402,683,539	411,604,263	423,370,462	428,564,773	433,830,939	439,170,047
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		162,345,060	164,474,940	166,627,065	169,878,669	174,290,700	175,299,094	176,312,282	177,330,290	185,930,574	219,587,916	221,111,166	222,646,450	224,193,873	229,482,144	242,178,517	244,816,376	247,486,932	250,190,642
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(F) STREET LIGHTING AND TRAFFIC CONTROL		7,321,167	7,505,737	7,694,960	7,888,953	7,338,790	7,523,804	7,713,482	7,907,942	8,107,305	8,177,335	8,247,970	8,319,214	8,391,075	8,463,556	8,533,055	8,603,126	8,673,771	8,744,997
SUBTOTAL - LOAD REQUIREMENTS		862,186,120	886,372,509	908,901,639	942,024,556	994,545,510	1,015,112,122	1,035,872,164	1,056,828,918	1,091,483,206	1,166,627,011	1,187,937,787	1,209,473,823	1,231,238,769	1,256,964,942	1,293,123,651	1,310,182,032	1,327,483,480	1,345,031,639
III. ESTIMATED SDG&E RATES ($/KWH):																			
(A) RESIDENTIAL		$0.075	$0.073	$0.071	$0.071	$0.072	$0.066	$0.067	$0.069	$0.070	$0.072	$0.073	$0.075	$0.077	$0.079	$0.081	$0.082	$0.082	$0.078
(B) SMALL COMMERCIAL (A)		$0.095	$0.092	$0.089	$0.090	$0.090	$0.083	$0.084	$0.087	$0.088	$0.091	$0.093	$0.095	$0.097	$0.099	$0.102	$0.104	$0.104	$0.100
(C) MEDIUM COMMERCIAL (AL-TOU)		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.099
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.099
(E) AGRICULTURAL		$0.094	$0.091	$0.088	$0.089	$0.089	$0.082	$0.083	$0.085	$0.087	$0.089	$0.091	$0.093	$0.096	$0.098	$0.100	$0.103	$0.103	$0.098
(F) STREET LIGHTING AND TRAFFIC CONTROL		$0.086	$0.084	$0.081	$0.082	$0.082	$0.075	$0.077	$0.079	$0.080	$0.082	$0.084	$0.086	$0.088	$0.090	$0.092	$0.095	$0.095	$0.090
IV. ESTIMATED SDG&E REVENUE REQUIREMENT ($):																			
(A) RESIDENTIAL		28,120,628	28,554,155	28,878,174	30,277,572	31,679,837	29,604,463	30,839,911	32,261,113	33,634,063	35,129,087	36,708,158	38,357,747	40,080,976	41,881,108	43,761,546	45,494,830	46,202,354	44,511,816
(B) SMALL COMMERCIAL (A)		5,990,652	5,878,012	5,779,565	5,933,270	6,106,529	5,615,510	5,766,157	5,941,896	6,181,619	6,609,587	6,821,896	7,041,207	7,267,753	7,501,773	7,740,994	8,000,542	8,075,374	7,819,959
(C) MEDIUM COMMERCIAL (AL-TOU)		23,941,453	23,469,440	23,055,211	24,288,944	27,120,223	25,584,180	26,922,364	28,407,732	30,312,579	33,538,386	35,147,141	36,816,012	38,547,070	40,342,453	42,488,253	44,039,398	44,580,551	43,269,117
(D) LARGE INDUSTRIAL (AL-TOU, + 500 KW)		15,184,954	14,901,564	14,654,164	15,058,798	15,542,330	14,293,773	14,677,090	15,124,822	16,204,840	19,585,711	20,191,201	20,816,108	21,461,063	22,492,169	24,304,346	25,157,378	25,431,805	24,649,969
(E) AGRICULTURAL		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
(F) STREET LIGHTING AND TRAFFIC CONTROL		631,448	627,095	624,141	644,830	603,446	565,846	592,096	621,929	651,369	672,266	694,151	716,770	740,147	764,308	788,945	814,398	821,086	790,789
TOTAL REVENUE REQUIREMENT		$73,869,135	$73,430,266	$72,991,255	$76,203,413	$81,052,365	$75,663,773	$78,797,618	$82,357,492	$86,984,471	$95,535,036	$99,562,547	$103,747,844	$108,097,009	$112,981,810	$119,084,083	$123,506,547	$125,111,169	$121,041,650
V. OPERATING EXPENSES ($):																			
(A) POWER SUPPLY AND DELIVERY:																			
(i) MARKET PURCHASES		$4,317,306	$4,975,119	$5,551,166	$6,807,146	$8,651,115	$9,134,242	$9,653,946	$10,282,916	$11,346,958	$13,953,670	$14,148,969	$14,136,942	$15,269,679	$16,780,898	$18,735,293	$19,739,659	$21,284,026	$21,756,753
(ii) CONTRACT PURCHASES		$3,188,640	$3,574,080	$4,555,200	$5,010,720	$5,921,760	$6,964,200	$8,041,680	$8,514,720	$9,460,800	$10,879,920	$11,607,000	$12,999,840	$13,972,200	$13,972,200	$13,972,200	$15,242,400	$15,242,400	$15,242,400
(iii) POWER PRODUCTION		$42,600,729	$41,475,777	$42,389,801	$42,600,729	$42,600,729	$43,092,896	$43,655,372	$43,444,443	$43,585,062	$43,585,062	$43,022,586	$42,671,039	$43,725,681	$44,428,776	$44,920,943	$45,905,276	$47,241,157	$46,889,609
(iv) DWR POWER		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(v) OPERATIONS AND SCHEDULING		$4,155,465	$4,215,931	$4,272,254	$4,355,061	$4,486,364	$4,537,780	$4,589,680	$4,642,072	$4,728,708	$4,916,568	$4,969,844	$5,023,685	$5,078,097	$5,142,412	$5,232,809	$5,275,455	$5,318,709	$5,362,579
(vi) ANCILLARY SERVICES & CAPACITY RESERVES		$1,501,179	$1,519,289	$1,619,387	$1,719,266	$1,863,002	$1,944,960	$2,032,745	$2,080,079	$2,185,047	$2,395,405	$2,418,693	$2,454,861	$2,586,458	$2,708,185	$2,847,559	$2,970,020	$3,122,211	$3,149,428
(vi) CALIFORNIA ISO COSTS		$897,568	$976,833	$1,062,877	$1,169,611	$1,329,738	$1,426,164	$1,527,529	$1,626,971	$1,770,764	$2,028,718	$2,154,045	$2,292,484	$2,426,619	$2,569,838	$2,748,797	$2,888,085	$3,026,975	$3,160,263
SUBTOTAL - POWER SUPPLY		$56,660,888	$56,737,029	$59,450,684	$61,662,533	$64,852,708	$67,100,241	$69,500,951	$70,591,201	$73,077,339	$77,759,343	$78,321,137	$79,578,851	$83,058,734	$85,602,309	$88,457,601	$92,020,895	$95,235,478	$95,561,032
(B) NON-BYPASSABLE CHARGES		$9,827,793	$9,148,056	$7,773,360	$8,658,598	$9,906,016	$10,477,193	$11,493,997	$11,802,461	$12,030,928	$12,883,159	$13,114,302	$13,347,659	$13,583,264	$13,866,451	$14,275,816	$14,460,466	$14,647,717	$9,140,796
TOTAL - OPERATING EXPENSES		$66,488,681	$65,885,085	$67,224,044	$70,321,131	$74,758,724	$77,577,434	$80,994,949	$82,393,662	$85,108,268	$90,642,502	$91,435,440	$92,926,510	$96,641,998	$99,468,760	$102,733,418	$106,481,361	$109,883,195	$104,701,828
(C) REVENUES FROM MARKET SALES:																			
(i) EXCESS ENERGY SALES		$5,956,334	$5,692,182	$5,870,259	$5,749,493	$5,556,794	$5,678,455	$5,810,537	$5,715,861	$5,670,200	$5,380,233	$5,342,758	$5,437,345	$5,525,122	$5,414,974	$5,179,116	$5,277,053	$5,299,668	$4,979,426
(ii) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - MARKET REVENUES		$5,956,334	$5,692,182	$5,870,259	$5,749,493	$5,556,794	$5,678,455	$5,810,537	$5,715,861	$5,670,200	$5,380,233	$5,342,758	$5,437,345	$5,525,122	$5,414,974	$5,179,116	$5,277,053	$5,299,668	$4,979,426
TOTAL EXPENSES NET OF MARKET REVENUES		$60,532,347	$60,192,902	$61,353,785	$64,571,638	$69,201,930	$71,898,980	$75,184,412	$76,677,801	$79,438,068	$85,262,269	$86,092,681	$87,489,166	$91,116,876	$94,053,786	$97,554,302	$101,204,308	$104,583,527	$99,722,402
VI. TOTAL BENEFITS																			
(A) SDG&E REVENUE REQUIREMENT		$73,869,135	$73,430,266	$72,991,255	$76,203,413	$81,052,365	$75,663,773	$78,797,618	$82,357,492	$86,984,471	$95,535,036	$99,562,547	$103,747,844	$108,097,009	$112,981,810	$119,084,083	$123,506,547	$125,111,169	$121,041,650
(B) CHULA VISTA REVENUE REQUIREMENT		$60,532,347	$60,192,902	$61,353,785	$64,571,638	$69,201,930	$71,898,980	$75,184,412	$76,677,801	$79,438,068	$85,262,269	$86,092,681	$87,489,166	$91,116,876	$94,053,786	$97,554,302	$101,204,308	$104,583,527	$99,722,402
(C) BENEFITS (SDG&E MINUS CHULA VISTA)	$89,643,990	$13,336,789	$13,237,364	$11,637,470	$11,631,776	$11,850,434	$3,764,794	$3,613,206	$5,679,691	$7,546,403	$10,272,767	$13,469,866	$16,258,678	$16,980,133	$18,928,024	$21,529,782	$22,302,239	$20,527,642	$21,319,248
(D) BENEFITS (% OF GENERATION RATES)	13.9%	18.1%	18.0%	15.9%	15.3%	14.6%	5.0%	4.6%	6.9%	8.7%	10.8%	13.5%	15.7%	15.7%	16.8%	18.1%	18.1%	16.4%	17.6%
(E) BENEFITS (% OF TOTAL RATES)	7.6%	10.2%	10.0%	8.9%	8.5%	8.2%	2.7%	2.5%	3.7%	4.7%	5.9%	7.4%	8.6%	8.7%	9.3%	10.1%	10.1%	9.2%	9.7%
NPV 2006-2023	$89,643,990	$13,336,789	$13,237,364	$11,637,470	$11,631,776	$11,850,434	$3,764,794	$3,613,206	$5,679,691	$7,546,403	$10,272,767	$13,469,866	$16,258,678	$16,980,133	$18,928,024	$21,529,782	$22,302,239	$20,527,642	$21,319,248
NPV 2006-2014	$51,763,524	$13,336,789	$13,237,364	$11,637,470	$11,631,776	$11,850,434	$3,764,794	$3,613,206	$5,679,691	$7,546,403									
NPV 2015-2023	$37,880,466	0	0	0	0	0	0	0	0	0	$10,272,767	$13,469,866	$16,258,678	$16,980,133	$18,928,024	$21,529,782	$22,302,239	$20,527,642	$21,319,248

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option

	Net Present Value	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
I. Customer Accounts																							
A. Residential		62,500	64,925	67,349	69,774	72,199	74,624	76,643	78,663	80,683	81,248	81,813	82,378	82,944	83,509	84,074	84,640	85,205	85,770	86,335	86,496	86,656	86,816
B. Core Commercial		3,370	3,411	3,513	3,735	3,784	3,833	3,882	3,954	4,045	4,069	4,092	4,116	4,190	4,377	4,413	4,449	4,485	4,521	4,556	4,599	4,642	4,685
C. Noncore Commercial		20	20	21	22	22	23	23	23	24	24	24	24	25	26	26	26	27	27	27	27	28	28
D. Noncore Industrial		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
E. Electric Generation		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Accounts		65,901	68,367	70,894	73,542	76,016	78,490	80,560	82,651	84,763	85,352	85,940	86,529	87,169	87,923	88,524	89,126	89,727	90,329	90,930	91,132	91,336	91,540
II. Gas Requirements (000 Therms)																							
A. Residential		20,600	21,293	21,977	22,655	23,395	24,132	24,786	25,439	26,092	26,275	26,457	26,640	26,823	27,006	27,189	27,371	27,554	27,737	27,920	27,972	28,023	28,075
B. Core Commercial		6,366	6,475	6,702	7,161	7,291	7,422	7,556	7,734	7,952	8,038	8,125	8,212	8,402	8,822	8,938	9,056	9,175	9,295	9,414	9,550	9,687	9,827
C. Noncore Commercial		5,000	5,086	5,264	5,625	5,727	5,830	5,935	6,075	6,246	6,314	6,382	6,450	6,600	6,930	7,021	7,113	7,207	7,301	7,395	7,501	7,609	7,719
D. Noncore Industrial		34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I		66,744	67,632	68,722	70,220	71,191	72,164	73,055	74,026	75,069	75,405	75,742	76,081	76,603	77,536	77,926	78,319	78,714	79,112	79,507	79,801	80,098	80,399
E. Electric Generation		110,184	113,489	116,894	120,401	124,013	0	0	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544
Total Requirements		176,928	181,122	185,615	190,620	195,204	72,164	73,055	331,570	332,613	332,949	333,286	333,625	334,147	335,080	335,470	335,863	336,258	336,656	337,051	337,345	337,642	337,943
% Increase			2.4%	2.5%	2.7%	2.4%	-63.0%	1.2%	353.9%	0.3%	0.1%	0.1%	0.1%	0.2%	0.3%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
III. Estimated SDG&E Delivery Rates ($/Therm) (Including SoCalGas Charges)																							
A. Residential		$0.394	$0.429	$0.436	$0.443	$0.451	$0.458	$0.466	$0.473	$0.481	$0.489	$0.497	$0.505	$0.513	$0.521	$0.530	$0.538	$0.547	$0.556	$0.564	$0.574	$0.583	$0.592
B. Core Commercial		$0.420	$0.405	$0.412	$0.419	$0.426	$0.433	$0.440	$0.448	$0.455	$0.462	$0.470	$0.477	$0.485	$0.493	$0.501	$0.509	$0.517	$0.525	$0.534	$0.542	$0.551	$0.560
C. Noncore Commercial		$0.078	$0.088	$0.089	$0.091	$0.092	$0.094	$0.095	$0.097	$0.098	$0.100	$0.102	$0.103	$0.105	$0.107	$0.108	$0.110	$0.112	$0.114	$0.115	$0.117	$0.119	$0.121
D. Noncore Industrial		$0.078	$0.088	$0.089	$0.091	$0.092	$0.094	$0.095	$0.097	$0.098	$0.100	$0.102	$0.103	$0.105	$0.107	$0.108	$0.110	$0.112	$0.114	$0.115	$0.117	$0.119	$0.121
E. Electric Generation		$0.019	$0.027	$0.028	$0.028	$0.029	$0.029	$0.030	$0.030	$0.031	$0.031	$0.032	$0.032	$0.033	$0.033	$0.034	$0.034	$0.035	$0.036	$0.036	$0.037	$0.037	$0.038
IV. Estimated SDG&E Non-Gas Revenue (000$) (Including SoCalGas Charges)																							
A. Residential		$8,112	$9,129	$9,580	$10,040	$10,541	$11,054	$11,542	$12,043	$12,558	$12,850	$13,147	$13,451	$13,761	$14,078	$14,401	$14,730	$15,067	$15,410	$15,760	$16,042	$16,329	$16,621
B. Core Commercial		$2,671	$2,625	$2,762	$3,000	$3,106	$3,214	$3,327	$3,462	$3,618	$3,716	$3,817	$3,920	$4,075	$4,348	$4,476	$4,607	$4,743	$4,882	$5,024	$5,178	$5,336	$5,500
C. Noncore Commercial		$388	$446	$469	$510	$528	$546	$565	$588	$615	$632	$649	$666	$693	$739	$761	$783	$806	$830	$854	$880	$907	$935
D. Noncore Industrial		$2,700	$3,050	$3,101	$3,153	$3,206	$3,259	$3,313	$3,368	$3,424	$3,479	$3,535	$3,592	$3,650	$3,709	$3,768	$3,829	$3,890	$3,953	$4,016	$4,080	$4,146	$4,212
Subtotal R/C/I		$13,871	$15,250	$15,913	$16,703	$17,380	$18,074	$18,748	$19,462	$20,215	$20,677	$21,148	$21,630	$22,179	$22,873	$23,406	$23,950	$24,506	$25,074	$25,654	$26,180	$26,718	$27,267
Average R/C/I $/Therm		$0.208	$0.225	$0.232	$0.238	$0.244	$0.250	$0.257	$0.263	$0.269	$0.274	$0.279	$0.284	$0.290	$0.295	$0.300	$0.306	$0.311	$0.317	$0.323	$0.328	$0.334	$0.339
E. Electric Generation Revenue		$2,093	$3,118	$3,265	$3,419	$3,580	$0	$0	$7,812	$7,942	$8,070	$8,200	$8,332	$8,466	$8,602	$8,740	$8,880	$9,023	$9,167	$9,314	$9,463	$9,615	$9,769
Total Revenue		$15,964	$18,368	$19,177	$20,122	$20,960	$18,074	$18,748	$27,274	$28,157	$28,747	$29,348	$29,961	$30,645	$31,475	$32,145	$32,830	$33,528	$34,242	$34,968	$35,643	$36,333	$37,036
Total Average $/Therm		$0.090	$0.101	$0.103	$0.106	$0.107	$0.250	$0.257	$0.082	$0.085	$0.086	$0.088	$0.090	$0.092	$0.094	$0.096	$0.098	$0.100	$0.102	$0.104	$0.106	$0.108	$0.110
V. Est. Chula Vista Operating Expenses (Including SoCalGas Charges)																							
A. C.V. Delivery Cost to R/C/I ($/Therm)			$0.152	$0.157	$0.161	$0.166	$0.171	$0.176	$0.182	$0.187	$0.193	$0.199	$0.205	$0.211	$0.217	$0.224	$0.230	$0.237	$0.244	$0.252	$0.259	$0.267	$0.275
B. C.V. Cost to Serve R/C/I (000$)			$10,294	$10,774	$11,339	$11,841	$12,363	$12,891	$13,454	$14,053	$14,539	$15,042	$15,563	$16,140	$16,827	$17,418	$18,031	$18,666	$19,323	$20,002	$20,679	$21,378	$22,102
C. Est. Cost to Serve Power Plant ($/Th)			$0.0010	$0.0010	$0.0011	$0.0011	$0.0011	$0.0012	$0.0012	$0.0012	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016	$0.0016	$0.0017	$0.0017	$0.0018	$0.0018
D. C.V. Cost to Serve PP (000$)			$113	$120	$128	$136	$0	$0	$308	$317	$326	$336	$346	$357	$367	$378	$390	$401	$413	$426	$438	$452	$465
G. SoCalGas Wholesale Rate ($/Th)			$0.018	$0.018	$0.018	$0.018	$0.019	$0.019	$0.019	$0.020	$0.020	$0.020	$0.021	$0.021	$0.021	$0.022	$0.022	$0.022	$0.023	$0.023	$0.024	$0.024	$0.024
H. Est. SDG&E Trans. Rate ($/Th)			$0.023	$0.023	$0.024	$0.024	$0.025	$0.025	$0.025	$0.026	$0.026	$0.027	$0.027	$0.028	$0.028	$0.028	$0.029	$0.029	$0.030	$0.030	$0.031	$0.031	$0.032
I. SoCalGas/SDG&E Cost to C.V. (000$)			$7,361	$7,669	$8,007	$8,337	$3,133	$3,225	$14,879	$15,174	$15,434	$15,698	$15,967	$16,249	$16,557	$16,842	$17,133	$17,428	$17,728	$18,034	$18,338	$18,648	$18,963
J. Capital Expense (000$)			$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418	$418
K. Capital Improvement Cost (000$)			$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958	$958
Total Expenses			$19,145	$19,940	$20,850	$21,689	$16,872	$17,492	$30,017	$30,920	$31,676	$32,453	$33,253	$34,122	$35,127	$36,015	$36,930	$37,872	$38,841	$39,838	$40,832	$41,854	$42,907
Total $/Therm			$0.106	$0.107	$0.109	$0.111	$0.234	$0.239	$0.091	$0.093	$0.095	$0.097	$0.100	$0.102	$0.105	$0.107	$0.110	$0.113	$0.115	$0.118	$0.121	$0.124	$0.127
VI. Estimated Benefit of Gas Utility																							
A. SDG&E Revenue minus CV Cost			($777)	($763)	($728)	($729)	$1,202	$1,256	($2,743)	($2,763)	($2,929)	($3,105)	($3,291)	($3,477)	($3,652)	($3,870)	($4,100)	($4,343)	($4,600)	($4,870)	($5,188)	($5,522)	($5,872)
B. Lost Franchise Fee			$657	$681	$689	$709	$650	$679	$858	$885	$905	$924	$938	$956	$978	$989	$1,002	$1,031	$1,055	$1,078	$1,104	$1,133	$1,146
Net Benefit/(Cost)	(24,327)		($1,434)	($1,444)	($1,418)	($1,439)	$552	$577	($3,601)	($3,648)	($3,834)	($4,030)	($4,229)	($4,433)	($4,630)	($4,859)	($5,102)	($5,374)	($5,655)	($5,948)	($6,292)	($6,655)	($7,017)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Chula Vista Customer Escalators																						
Residential		1.039	1.037	1.036	1.035	1.034	1.027	1.026	1.026	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.002	1.002	1.002
Core Commercial		1.012	1.030	1.063	1.013	1.013	1.013	1.018	1.023	1.006	1.006	1.006	1.018	1.045	1.008	1.008	1.008	1.008	1.008	1.009	1.009	1.009
Noncore Commercial		1.012	1.030	1.063	1.013	1.013	1.013	1.018	1.023	1.006	1.006	1.006	1.018	1.045	1.008	1.008	1.008	1.008	1.008	1.009	1.009	1.009
Noncore Industrial		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Electric Generation		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Chula Vista Usage per Customer Escalator																						
Residential		0.995	0.995	0.995	0.998	0.998	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Core Commercial		1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005
Noncore Commercial		1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005	1.005
Noncore Industrial		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Electric Generation		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Chula Vista Gas Demand Escalator																						
Residential		1.034	1.032	1.031	1.033	1.032	1.027	1.026	1.026	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.002	1.002	1.002
Core Commercial		1.017	1.035	1.069	1.018	1.018	1.018	1.024	1.028	1.011	1.011	1.011	1.023	1.050	1.013	1.013	1.013	1.013	1.013	1.014	1.014	1.014
Noncore Commercial		1.017	1.035	1.069	1.018	1.018	1.018	1.024	1.028	1.011	1.011	1.011	1.023	1.050	1.013	1.013	1.013	1.013	1.013	1.014	1.014	1.014
Noncore Industrial		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Electric Generation		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
SDG&E/SoCalGas Rate Escalators			1.017	1.017	1.017	1.017	1.017	1.017	1.017	1.016	1.016	1.016	1.016	1.016	1.016	1.016	1.016	1.016	1.016	1.016	1.016	1.016
South Bay Must Run EG Escalator		1.03	1.03	1.03	1.03	0.00	0.00														30-yr avg	1.016
South Bay Replacement Power Plant																						
Capacity MW								600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Capacity Factor								70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Generation MWh								3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200
Heat Rate Btu/kWh								7000	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000	7000
Gas Reqmts (000 Th)								257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544	257,544

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Chula Vista Utility Cost Inputs											
O&M Cost Escalator		1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
SDG&E Gas Rate Base (000$)		$423,226									
Chula Vista Share Based on Non-EG Th		4.8%									
Acq Cost Based on Non-EG Th (000$)		$20,446									
Acquisition Cost Multiple		1.64									
Est. Acquisition Cost (000$)		$33,531									
Start-up Capital Cost (15%)		$5,030									
Total Cost to Acquire		$38,560									
Annual P&I (30-yr loan @ 6.5% Rate)		$418	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3
Cap Improvement Cost (35 yr dep)		$958	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0
Gas Price at Topock $/Dth	3.10	5.22	5.19	4.81	4.73	4.57	4.70	4.71	4.73	4.81	4.88
SDG&E Bundled Sales (Core Res/Comm) (000 Therms)	26,966	27,768	28,679	29,816	30,686	31,555	32,342	33,173	34,044	34,313	34,582
SDG&E procurement Rev (000$	$8,350	$14,488	$14,884	$14,342	$14,514	$14,421	$15,201	$15,624	$16,103	$16,504	$16,876
Est Total SDG&E Rev in CV 000$	$24,315	$32,856	$34,062	$34,464	$35,474	$32,494	$33,948	$42,898	$44,260	$45,251	$46,224
Est Franchise fee @ 2.0%	$486	$657	$681	$689	$709	$650	$679	$858	$885	$905	$924
C.V. Cost to Serve Power Plant ($/Th)		0.0416	0.0423	0.0430	0.0438	0.0445	0.0452	0.0460	0.0467	0.0475	0.0483
SDG&E EG Rate ($/Th)		0.027	0.028	0.028	0.029	0.029	0.030	0.030	0.031	0.031	0.032
Profit/(Loss) from Power Plant ($/Th)		(0.0142)	(0.0144)	(0.0146)	(0.0149)	(0.0151)	(0.0154)	(0.0156)	(0.0159)	(0.0162)	(0.0164)
Annual Profit/(Loss) from Power Plant		($1,608)	($1,684)	($1,763)	($1,847)	$0	$0	($4,030)	($4,097)	($4,163)	($4,230)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
O&M Cost Escalator	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Annual P&I (30-yr loan @ 6.5% Rate)	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3	$418.3
Cap Improvement Cost (35 yr dep)	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0	$958.0
Gas Price at Topock $/Dth	4.86	4.87	4.87	4.79	4.74	4.90	5.00	5.07	5.21	5.39	5.34
SDG&E Bundled Sales (Core Res/Comm) (000 Therms)	34,852	35,225	35,828	36,127	36,427	36,729	37,032	37,334	37,521	37,711	37,902
SDG&E procurement Rev (000$	$16,938	$17,155	$17,448	$17,305	$17,267	$17,997	$18,516	$18,928	$19,549	$20,326	$20,240
Est Total SDG&E Rev in CV 000$	$46,900	$47,800	$48,923	$49,450	$50,096	$51,526	$52,758	$53,896	$55,192	$56,659	$57,275
Est Franchise fee @ 2.0%	$938	$956	$978	$989	$1,002	$1,031	$1,055	$1,078	$1,104	$1,133	$1,146
C.V. Cost to Serve Power Plant ($/Th)	0.0490	0.0498	0.0506	0.0514	0.0523	0.0531	0.0540	0.0548	0.0557	0.0566	0.0575
SDG&E EG Rate ($/Th)	0.032	0.033	0.033	0.034	0.034	0.035	0.036	0.036	0.037	0.037	0.038
Profit/(Loss) from Power Plant ($/Th)	(0.0167)	(0.0170)	(0.0172)	(0.0175)	(0.0178)	(0.0181)	(0.0184)	(0.0187)	(0.0190)	(0.0193)	(0.0196)
Annual Profit/(Loss) from Power Plant	($4,298)	($4,367)	($4,437)	($4,508)	($4,581)	($4,654)	($4,729)	($4,805)	($4,881)	($4,960)	($5,039)

III. NATURAL GAS SUPPLY FOR POWER GENERATION

A. Natural Gas Supply Outlook

The United States Geological Survey (USGS) estimates a resource base in the United States of approximately 1,000 Trillion Cubic Feet (Tcf), which, when combined with a Canadian resource base of approximately 500 Tcf, yields enough natural gas in the ground to meet demand for 50 years. The Energy Information Administration (EIA) in "U. S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report" (November 2002) reported a level of proved and probable reserves of 1,431 Tcf for the Lower-48 states. A December 1999 report of the National Petroleum Council (NPC) reported a resource base of 1,466 Tcf in the Lower-48, 333 Tcf in Alaska, and 667 Tcf in Canada, for a total of 2,289 Tcf. The EIA estimated reserves would be sufficient to sustain current production levels of approximately 20 Tcf per year for the next 65 to 70 years. The NPC estimated reserves would be sufficient for more than 100 years.

By either count, the total reserve base, combined with an understanding of reserve appreciation and the role of technology in recovering these reserves, leads to a conclusion that a large natural gas resource base exists and supports the corollary conclusion that reserves are adequate to meet market demand in the United States.

1. California Gas Supply

Five different supply basins produce natural gas available for consumers in California as well as to other markets.[49] These supply basins include: the San Juan basin, located in the Four Corners region (New Mexico, Arizona, Utah, and Colorado); the Permian Basin of eastern New Mexico and West Texas; the Rocky Mountain producing areas in Wyoming, Utah and western Colorado; the Sacramento basin in California; and the Western Canadian Sedimentary Basin (WCSB) that covers most of Alberta and extends into northeastern British Columbia and southwestern Saskatchewan. These basins contain proved reserves totaling some 135 Tcf. Proven reserves and general production levels from these supply basins are shown in Table 1.

[49] A map showing the location of these supply basins and the pipelines that deliver their production to California are shown in Figure 1.

Table 1
Supply Basin Characteristics

Basin	Proved Reserves (Tcf)	Production (Tcf/yr.)
WCSB	68.0	5.9
San Juan	13.9	1.1
Permian	13.1	1.5
Rockies	36.8	1.1
California	3.2	0.3
TOTAL	135	8.9

While production from the indicated basins can flow to markets other than California markets, those other markets tend to be fully served with supply from other basins that can reach them more economically than can supply from these western production areas. Production from the supply basins tabulated above at least historically has been delivered primarily to California.

According to the EIA, California is the nation's second largest consumer of natural gas. In 2001, California averaged approximately 6.6 Bcf daily use. Table 2 below contains recorded and forecasted natural gas consumption in California by sector, with 2001 reflecting the latest recorded data. Residential and commercial demand was fairly constant over the period, generally reflecting the variations in weather, while industrial usage was more variable over the same period. The electric generation (EG) sector grew more than 1,000 MMcfd over the five-year period. This increase occurred as merchant power plants and cogeneration facilities came on line and California's economy grew.

Table 2

Recorded California Gas Demand
Average Daily MMcfd

Year	Residential	Commercial	Industrial	Electric Generation	Total
1997	1,312	696	1,970	1,633	5,611
1998	1,507	773	2.044	1,788	6,101
1999	1,556	671	1,989	1,981	6,197
2000	1,414	674	2,126	2.449	6,663
2001	1,405	674	1,825	2,677	6,581

Recorded Data Source: Energy Information Administration

California gas utilities are required to provide to the California Energy Commission compiled operational data and forecasts annually in The California Gas Report (CGR). Recorded and forecast data contained in Table 3 below was provided by SDG&E in the 2002 CGR. The forecast years assumes average temperature years. The demand projection SDG&E submitted for the CGR assumes that virtually all new electric generation will be built outside their service area and that existing EG demand will be displaced by power imported from Mexican generation projects.

Table 3
SDG&E Average Daily Demand
MMcfd

Year	Core	Noncore	EG	Total
Recorded Years 1997-2001				
1997	120	29	178	329
1998	134	26	204	364
1999	144	22	179	349
2000	132	21	228	388
2001	139	12	276	424
Forecast Years 2002-2022				
2002	140	9	179	331
2003	147	6	88	243
2004	146	6	86	241
2005	147	6	116	271
2006	148	6	117	274
2007	151	6	119	278
2010	158	6	126	293
2015	168	6	199	376
2020	178	7	215	402
2022	182	7	221	413

SDG&E also forecasts Firm Service Demand (FSD), which corresponds to the 1-in-10 cold-year reliability standard for firm noncore service. FSD has a 10% probability of occurring in any given year; all else equal, it should be expected to occur once in every ten years. The firm noncore demand represented in the Table 4 below is forecast average daily demand for all noncore customers. Thus, noncore peak demand is not included.

Table 4.
Forecast Firm Service Demand

Year	Core	Firm Noncore	Firm EG	Total
2003	385	64	70	519
2004	388	64	67	519
2005	392	64	65	521
2006	398	64	100	562
2007	404	64	136	604
2008	409	64	170	643
2009	413	64	174	651
2010	419	64	177	660
2011	424	65	181	670
2012	429	65	184	678
2013	435	65	188	688
2014	439	65	192	696
2015	444	65	196	705
2016	449	65	199	713
2017	454	65	203	722

The current import limitation into SDG&E's service territory is 640 MMcfd; hence the possibility of curtailment arises as early as 2008 according to SDG&E's FSD.

2. Natural Gas Transportation Infrastructure

Five interstate pipelines bring natural gas from the western supply basins to serve consumers in California. These pipelines can deliver nearly 8 Bcf (*see* Table 5 below) of natural gas per day into California. Figure 1 below illustrates the location of natural gas production basins and the pipelines that connect these supply areas to California.

The pipelines into California are the following:

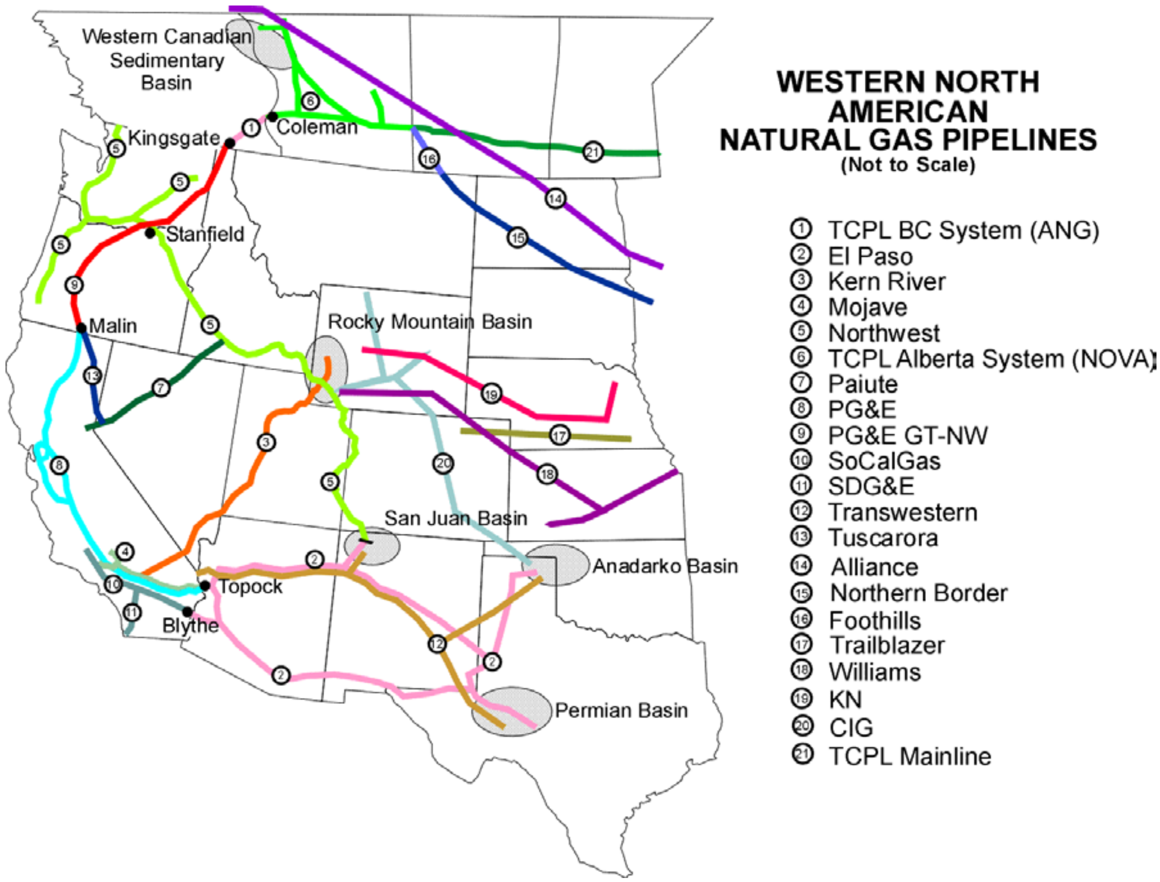
(1) PG&E Gas Transmission - Northwest (PG&E GT-NW), still commonly known as PGT), a unit of PG&E Corporation's National Energy Group, delivers Canadian gas to California. PGT is currently fully subscribed, the primary shippers are PG&E, natural gas marketers, and producers.

(2) Two interstate pipeline companies, El Paso Natural Gas and Transwestern, transport supplies produced in the Permian basin of West Texas and Southeastern New Mexico into California. Transwestern follows a northern route to pick up San Juan basin supplies from its San Juan

Lateral, and then proceeds to California terminating at Topock, and Needles, California. El Paso's southern system follows a route roughly paralleling the Mexican border to California, while its Line 1300 parallels Transwestern from Permian to San Juan where it connects to El Paso's northern system (San Juan basin to Topock).

(3) Rocky Mountain supply is delivered to California primarily via Williams affiliate Kern River Gas Transmission (Kern River). Kern River has a delivery capacity of approximately 1.8 Bcf per day to the California border, with the 2003 Expansion adding 0.9 Bcf per day. Much of this gas is delivered to directly connected end-users in Kern County, and large cogeneration projects near Bakersfield, or is delivered into the SoCal Gas system, or is utilized in growing markets in Utah and Nevada. Kern River is fully subscribed, primarily by shippers who own production in the Rockies and market their own production. Kern River has access to Canadian supplies by means of a connection with Northwest Pipeline at Muddy Creek in the vicinity of the Opal Hub. Northwest moves Canadian supplies south from Sumas, Washington and Rocky Mountain supplies north from Opal for delivery to PGT at Stanfield, Oregon.

Figure 1
Western Natural Gas Pipelines



Source: CEC

(4) Mojave is an extension of El Paso and Transwestern that cross into California at Topock. It proceeds to Daggett, California, paralleling lines owned by PG&E and SoCal Gas, where it connects to Kern River. Kern River and Mojave then continue as a single pipeline, operating jointly, to Bakersfield.[50] Mojave allows another 400 MMcf per day to enter California, but receives its supply from either El Paso or Transwestern. El Paso has border capacity totaling 3.29 Bcf per day, sufficient to accommodate Mojave.

(5) Questar Corporation purchased what was known as Line 90 (an oil pipeline) from ARCO, renamed it the Southern Trails Pipeline and converted it to transport natural gas in 2002. The converted line is

50 Because of the "pipe within a pipe" structure and joint operations beginning at Daggett, the two pipelines are frequently referred to as the "Kern/Mojave system."

currently capable of transporting 90MMcf per day from the San Juan basin and Rockies and terminates near the California border at Kingman, Arizona and into the SoCal Gas system. This pipeline is not shown in Figure 1.

The capacity of all pipelines to California is tabulated in Table 5.

Table 5
Pipeline Capacity into California[51]
Bcf/day

Pipeline	Capacity (Bcf per day)
PG&E-GT Northwest	1.940
Transwestern	0.800
El Paso Natural Gas	2.890
Kern River Gas Transmission	1.724
Mojave	0.400
Questar Southern Trails	0.090
Total	7.844

At the current time, significant natural gas demand is forecast to increase particularly in the Desert Southwest area. The Desert Southwest is located directly east and adjacent to some of the same major interstate pipeline capacity listed above which serves the southern California and San Diego areas. Over the last several years, the Desert Southwest has attracted a proliferation of gas fired cogeneration capacity, some of which is already on-line and more of which is scheduled to come on-line over the course of the next few years. Other gas load growth in the area has occurred as a result of the double-digit annual growth rate percentages in the population base over the last half decade or more, especially in the Las Vegas and Phoenix metropolitan areas. While certainly the strengthening demand growth in the Southwest could be seen as competition for Southern California requirements, natural gas market forces have responded to this market dynamic.

New pipeline capacity has been built accessing new supply from the Rockies with the Kern River pipeline expansion of 900 MMcf/d of capacity coming on-stream in April of 2003 delivering to meet load growth in the southwest and Southern California. Several other natural gas pipeline projects are proposed for the Desert Southwest including the 750 MMcf/d Silver Canyon Pipeline from the Rockies,

51 Pipeline capacity is adjusted for intrastate take-away capacity at the California border.

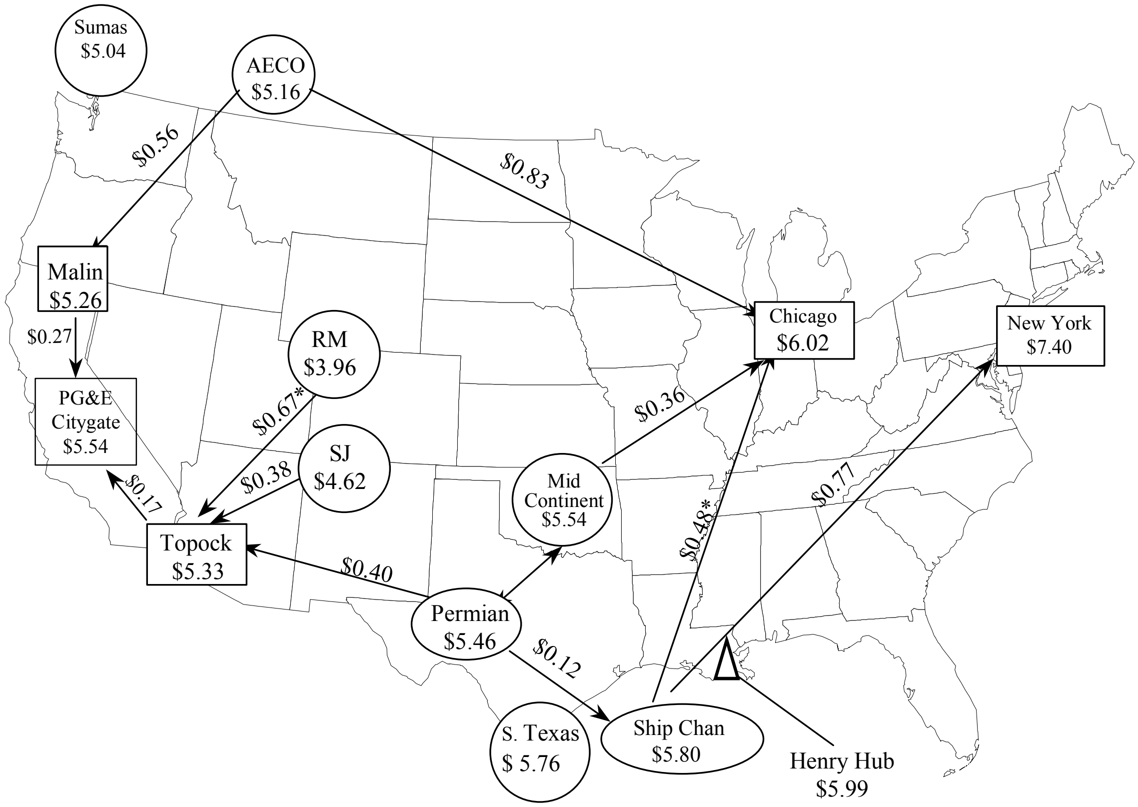
Transwestern's 1 Bcf/d Sun Devil pipeline proposal, the 750 MMcf/d Coronado Pipeline proposed by several San Juan producers, the 1 Bcf/d Pichacho oil pipeline conversion project across the southwest into SoCal Gas and the expansion of the Baja North pipeline to access new LNG gas supply from projects planned in the Baja California peninsula of Mexico. The composite of all this is that (1) the natural gas resource base exists currently and likely for the useful life of new generation to be built over the next few years and, (2) that adequate gas pipeline infrastructure has been proposed with some built and more likely to be built to serve the growing needs of both the Desert Southwest and Southern California market areas.

3. Basis Differentials

Relevant to the construction of new pipeline capacity is the role of basis differentials. Basis differentials are a function of supply available from a given basin, the cost of the transportation to move it to market, and which basin provides the marginal supply. They reflect the relative balance of supply versus demand in a given market and the cost of alternative supplies available to that market. In general, the marginal supply sets price; the infra-marginal suppliers sell at that same price, netting out their cost of transportation and other expenses from the revenues they receive. The price differentials between supply basins and markets or between one supply hub and another are known as "basis differentials." These differentials capture the differences in the value of supply between locations. A high basis differential occurs when demand in a given market is high relative to the supply available to serve it. Conversely, low differentials suggest over-supply relative to demand between a supply basin and its market.

Figure 2 below compares the average gas cost at major supply basins and market centers to the cost of pipeline transportation for various North American transportation links over the first six months of 2003. Supply basins are denoted with circles; market centers denoted by squares. The lines connecting supply basins to markets show the maximum tariffed cost of transporting gas from supply basins to market centers. New transportation is not likely to be built between that supply basin and market center until the basis differential reverses and grows to be larger than the current cost of transportation. The ability to earn such economic rents would attract the new entry needed to add transportation infrastructure. For example, the basis from the San Juan and Rockies basins and the Southern California in Figure 2. In both cases the basis are substantially above the existing transportation rates to the Southern California border. These basis differentials are what attracted pipeline projects to be proposed to allow shippers on the pipelines the opportunity to capture some of the margin from holding capacity on these pipelines.

Figure 2
U. S. Major Supply Basin and Market Center Prices
January – June 2003

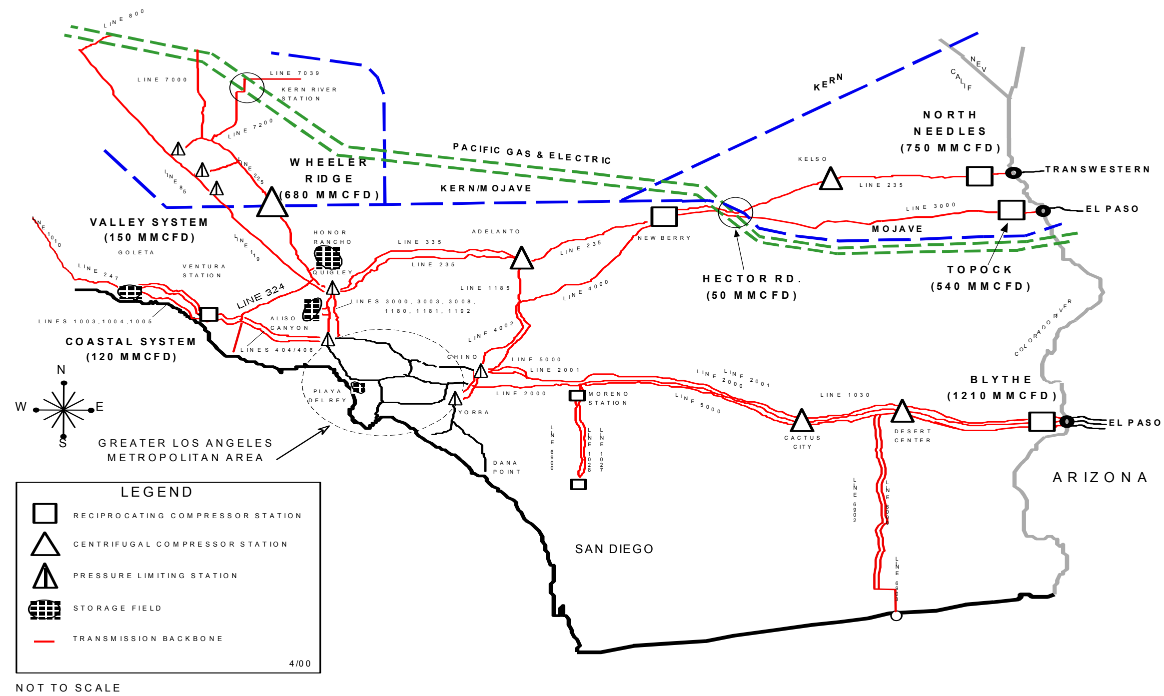


4. California Intrastate Transportation

Transportation within the state of California, with the major exception created by Kern River and Mojave as interstate pipelines subject to federal jurisdiction, is currently the domain of the state's two large gas distribution companies, PG&E and SoCal Gas, and a handful of other gas distribution utilities or municipal utilities -- such as SDG&E, Southwest Gas, and the City of Long Beach. SoCal Gas and PG&E both take gas from the interstate pipelines that terminate at the state line and move it to the state's major load centers, serving additional communities along the way.

SoCal Gas' backbone pipeline system covers southern California from the San Joaquin Valley south to the Mexican border. SoCal Gas' system delivers gas to its own local transmission system (for delivery to core and noncore end-users), SDG&E, the City of Long Beach, some large industrial generators and customers, and to storage. Figure 3 shows the SoCal Gas backbone transmission system.

Figure 3
Southern California Backbone Transmission System



Source: SoCal Gas

With recent additions of capacity[52] from expansion projects totaling 375 MMcfd, California SoCal Gas' transmission system gas available firm backbone capacity of 3,875 MMcfd is divided among the receipt points tabulated in Table 6 below.

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[52] The expansion projects include: Kramer Junction, 200MMcfd; Wheeler Ridge, 85 MMcfd; North Needles, 50 MMcfd; and Line 85, 40 MMcfd.

Table 6
SoCal Gas Backbone Receipt Point Capacity

SoCal Gas Receipt Point	Capacity, MMcfd
Blythe (Ehrenberg)	1,210
Topock	540
North Needles	750
North Needles Expansion	50
Hector Road	50
Wheeler Ridge (North)	520
Wheeler Ridge (South)	245
Line 85	190
North Coastal	120
Kramer Junction	200
Total	3,875

B. SDG&E Gas Transmission System

The SDG&E natural gas delivery system is capable of delivering 640 MMcf/d of gas on a firm basis to core and non-core customers. With one major exception, SDG&E customers have experienced few curtailments of gas service.[53] In the past SDG&E's interruptible customers have enjoyed a high level of service in spite of their interruptible service due to SDG&E's Abnormal Peak Day (APD) planning criteria. This 1-in-35-year criterion provides for a design that meets CPUC standards of least cost planning, and serves the interests of core customers. Non-core and EG customers however who suffered the curtailments in 2000/2001 were not as satisfied with the old standard and demanded a new planning and curtailment system. The Comprehensive Settlement Agreement (CSA) (OII 00-11-002) directed SDG&E to adopt a 1-in-10 (one curtailment in ten years), cold year conditions, reliability standard for SDG&E, for the core and non-core customers.

This change in curtailment standards alone was a step in the wrong direction in adding additional reliability assurances for the non-core. However these changes, combined with other safeguards that were included in the CSA (*e.g.,* allowing SDG&E to only offer firm non-core service when it has the capacity and authorizing curtailments to EG's on a pro-rata basis and curtailment of firm service for non-core customers on a rotating block basis in the event curtailments from the EG's is insufficient), should serve to help EG and non-core customers. Prior to the adoption of pro-rata curtailments for EG's, SDG&E's Gas Tariff Rule 14 provided for curtailments,

[53] SDG&E curtailed service to firm noncore customers on 17 days between November 2000 and March 2001 during the height of the California energy crisis.

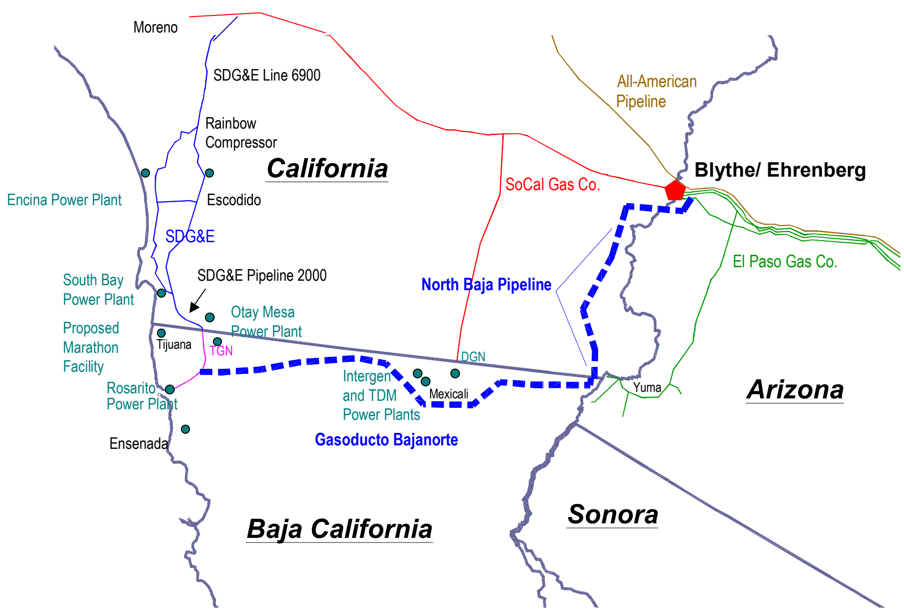
including non-core commercial and industrial customers and EG's on a rotating block basis. Other provisions in the CSA directed SDG&E to file reports with the CPUC twice per year on its capacity planning, demand forecast and status of expansion projects. This provision is directed at improving the system planning process by SDG&E to further improve service reliability.

The primary pipeline facilities on the SDG&E system consist of a 30-inch diameter pipeline and a 16-inch diameter pipeline that extent south from the Rainbow meter station at the Riverside-San Diego county line. The 30-inch line heads west from Rainbow and the 16-inch line leaves Rainbow and heads directly south. The two local transmission lines are interconnected in two locations as they head south.

SDG&E also owns and operates a major compressor station at Moreno Valley, situated 33 miles north of the San Diego county line. SDG&E installed this compressor station in SoCal Gas service territory to boost the pressure coming off of their major transmission line bringing gas in from the Southwestern gas basins. The Moreno station provides pressure to the SoCal Gas lines 1027, 1028, and 6900 that comprise the Moreno-to-Rainbow transmission corridor. Line 6900 was expanded by 70 MMcf/d in 2001, which increased the SDG&E system capacity to 640 MMcf/d from 570 MMcf/d.

Figure 4 below shows local pipeline infrastructure and existing and proposed power plant locations on the SDG&E system. In addition to the South Bay, Encina and Otay Mesa locations, we show existing and proposed power plants in the vicinity of Mexicali, Mexico, and the proposed Rosarito Power Plant in Tijuana.

Figure 4
SDG&E and Area Pipeline Infrastructure



Source: PG&E NEG; additional detail by NCI

While not strictly part of the SDG&E intrastate system, but increasingly important and integral to the SDG&E system (not unlike the SoCal Gas system is some respects), is the Mexican North Baja Pipeline (NBP) immediately to the south of the SDG&E service territory and shown in Figure 4.

This pipeline is owned by PG&E National Energy Group (PG&E NEG) and its 50% partner Sempra Energy. The NBP was completed in March 2003 and has capacity to transport up to 510,000 MMBtu per day of natural gas from an interconnect with El Paso Natural Gas at Ehrenberg, AZ into California at Blythe. The pipeline crosses into Mexico east of Mexicali, and continues westerly across northern Baja California, and terminates at an interconnection with TGN Pipeline between Rosarito, Mexico and San Diego, some 8-9 miles south of the U.S. – Mexico international border. The pipeline serves power projects at Mexicali and Rosarito, Mexico. The 77-mile U.S. segment of the pipeline is operated by PG&E National Energy Group, and is regulated by the FERC. The 135-mile Mexican portion of North Baja Project is the responsibility of Sempra Energy International and Proxima Gas, and is regulated by Mexico's Energy Regulatory Commission (CRE). Indirectly interconnected to the NBP, SDG&E's Pipeline 2000 and associated export facility was placed in service in April 2000 with capacity of up to 300,000 MMBtu per day. The Mexican portion of the line, commonly referred to as either Rosarito Pipeline or Transportadora de Gas Natural de Baja

California (TGN), is owned by Sempra Energy International (a partner in NBP). The TGN line extends into Mexico some 23 miles to Rosarito, where it serves an existing power plant, the Presidente Juarez. Prior to completion of the North Baja Pipeline, SDG&E delivered approximately 90,000 MMBtu per day into TGN for use at Rosarito. Upon completion of the North Baja Pipeline, SDG&E no longer supplies gas to the Rosarito generation facilities. At some time in the future (not currently planned) SDG&E may choose to import gas from TGN. This would be accomplished by modifying the existing facility to permit reversing the direction of flow, and by obtaining the requisite approvals.

Also of note regarding the NBP are the actions taken by Calpine at the Otay Mesa power project which is being developed by Calpine. Calpine has taken steps to become the sole importer of natural gas from North Baja Pipeline into the U.S. through its planned import facilities and service lateral. Calpine has plans for building, from its project site, a 1.5-mile long, 16-inch diameter service lateral capable of delivering 100 percent of the project's natural gas requirements. This lateral would connect Otay Mesa to SDG&E's Pipeline 2000, as well as to a natural gas import facility connected to the TGN Pipeline in Mexico. The import facility will consist of 340 feet of 16" pipe connecting to the Mexico side with a meter on the U.S. side. The import facility is licensed to provide natural gas only to Otay Mesa. Upon completion of the facilities, the Otay Mesa plant would be dually connected to both SDG&E and NBP and further would possess the ability to take its full load exclusively from either source.

Storage

Underground storage is important in California and for SDG&E customers in meeting winter loads of core customers as well as managing load swings from power generators. Between the LDC's and two independent storage providers, some 160 Bcf of storage inventory is available in the state.[54] SDG&E, however, has no physical gas storage capability within its service region. SDG&E has access to underground storage facilities located on SoCal Gas. SDG&E may contract for storage service from SoCal Gas, with special provisions to allow noncore customers located behind its Citygate access to that storage.

C. SDG&E Rates, Regulation and the Comprehensive Settlement Agreement

The delivered cost of natural gas to an end-user in southern California is the cost of gas at the California border plus the cost of intrastate transportation. Electric generation customers in the SoCal Gas and SDG&E currently pay the same rate,

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54 SoCal Gas owns and operates 110 Bcf of working storage capability (70 Bcf is reserved for core customers); PG&E owns 36 Bcf (virtually all of which is reserved for core customers or for system balancing). Private providers Wild Goose Storage Incorporated (WGSI) and Lodi Gas Storage (Lodi) add an additional 26 Bcf, and are located in northern California.

regardless of where a power project was actually located. SDG&E Rate Schedule EG currently provides for transportation of gas across both the SoCal Gas and SDG&E pipeline systems to the customer's end-use meter. The current blended rate for customers of both SoCal Gas and SDG&E is $0.2747 per MMBtu. SDG&E's Rate Schedule EG-SD, in contrast, provides for receipt of gas at the Rainbow receipt point into the SDG&E system. Customers who receive service under Schedule EG-SD must choose either firm or interruptible services. Firm service customers must pay full tariff rates, while interruptible customers may negotiate lower rates with SDG&E. The current full tariff rate for Schedule EG-SD is $0.0976.

In December 2001, the CPUC adopted most provisions of a "Comprehensive Gas OII Settlement Agreement (CSA)" that had been submitted to the CPUC in April 2000. Under these new rules, SoCal Gas will auction access to backbone transmission facilities and provide transportation service on those facilities at rates unbundled from the cost of local transmission or distribution, much as PG&E has done since 1998.

SDG&E has never focused on providing unbundled transportation in the same way as SoCal Gas or PG&E, and no provision to do so was contained in the settlement. Owing to its much smaller size and the fact that there is in fact little industrial or electric generation gas usage in its service area, the CPUC never forced SDG&E to stop providing natural gas procurement services to non-core customers. Thus, transportation of customer-owned gas on the SDG&E system is uncommon, although it is currently permitted under Rate Schedules EG for non-utility electric generators and rate Schedule NT for other non-core customers.

Under the CSA, SoCal Gas will reserve a total of 1,044 MMcfd (313 at North Needles, 303 at Topock, 355 at Blythe (Ehrenberg), and 73 at North Coastal) for core customers and will assign to SDG&E, 50 MMcf/d at Hector Road and 10 MMcf/d at Blythe (Ehrenberg). The remaining firm backbone rights will be offered to the market in an open season. No SoCal Gas capacity is reserved for serving SDG&E's non-core (including EG) customers, implying that they must participate in the open season to obtain their own SoCal Gas backbone transmission capacity or purchase at the SDG&E "Citygate".[55] SDG&E's interconnect with SoCal Gas at the Rainbow compressor station is a firm delivery point on the SoCal Gas system.

The auction of backbone transmission capacity will be a three-stage open season process. In the first two stages of the open season, existing end-use and wholesale customers, based on their historical requirements, will have the opportunity to obtain up to 50 percent of receipt point capacity not reserved by SoCal Gas for core customer gas acquisition and service. In the third stage of the open season, SoCal Gas will offer at least 20 percent of the remaining capacity to any creditworthy entity for a term of one

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[55] Rainbow will become the SDG&E "Citygate," – especially as gas from North Baja (at this time) will not be able to reach SDG&E customers other than Otay Mesa.

year only (to be offered again in subsequent open seasons), and will release all remaining capacity for the term of the settlement agreement. In the open season, prospective shippers will be allowed to bid either a rate design with a 100 percent reservation charge or a rate design with 50 percent of the total rate in the reservation charge and 50 percent in a volumetric charge. The rates proposed in the settlement agreement are $.07191 for the 100 percent reservation option, and $0.07591 for the 50/50 option. The 100 percent reservation rate design and the 50/50 rate design will be given equal weight for consideration in the open season. The Comprehensive Settlement "pools" together deliveries across the individual SoCal Gas delivery points to create a virtual "SoCal Gas Citygate" much as was done by PG&E in its Gas Accord structure.

Additional operational provisions of the CSA include definition of receipt point capacity on the SoCal Gas backbone system, splitting the current transportation rate into backbone and local transmission/distribution components, creation of pooling rights on SoCal Gas backbone system, creation of a secondary market for trading firm receipt point capacity, and tighter balancing provisions to implement OFO's.

SoCal Gas and SDG&E filed proposed tariff revisions required to implement the CSA in a series of Advice Letters submitted between January and May 2002. CPUC denied SoCal Gas' nine Advice Letters without prejudice, and ordered SoCal Gas to file by June 30, 2003, an application proposing how to implement the CSA, and to describe any new issues arising from developments in the southern California gas market that would impact provisions of the CSA since its signing in April 2000. Advice Letters submitted by SDG&E, dealing with pass-through costs of transportation and storage pursuant to implementation of the CSA by SoCal Gas, were suspended by the CPUC dependent on the outcome of the SoCal Gas case.

D. Natural Gas Prices

The MEU Study Team looks to the volatility in natural gas prices over the last 2 - 3 years and the reaction by the industry to gain confidence in our theory that the general availability of natural gas supply will remain adequate to serve the region, including new power projects.

U.S. natural gas prices demonstrated a relatively stable pattern from 1996 through mid-2000, fluctuating between $2.00 and $3.00 per MMBtu. Gas prices began a significant run-up in mid-2000, grabbing headlines amid claims that supply was inadequate. Additionally, a general industry-wide expectation that gas prices would drop led many in the industry to delay their purchases of natural gas for injection into underground storage. By August and September 2000, prices had not dropped, the storage re-fill was behind schedule, and those needing to purchase gas for storage found themselves in an already-tight market where their need to acquire gas served to exert even more pressure on gas supplies and price levels.

By the start of the winter injection season, storage inventories were at their lowest in several years and traders pushed the NYMEX gas futures market closing price at Henry Hub for January 2001 to $9.98 per MMBtu – the highest level ever experienced. Importantly, it is at this point that demand began to decline. Colder winter weather failed to materialize. Non-weather-related demand also began to diminish as industries such as fertilizer and chemicals reduced production or moved to lower-cost production areas out of the U.S. Demand further declined as the economy began to slow down. Lower demand, combined with an increase in production brought about by significantly increased drilling activity and record active rig counts, created a net change in natural gas available of about 1.3 Tcf. So lower demand and increased production made more gas available. Prices declined steadily over 2001 as a result. From an economic perspective, the market worked exactly as it should: market-clearing prices rose until demand declined.

Prices in California reflected these same market dynamics. From 1997 through 1999, prices at Topock generally paralleled prices at Henry Hub, albeit with a small basis differential that varied month-to-month. Prior to that, Topock frequently traded at a discount to Henry Hub.

In late August 2000, an explosion on the El Paso's southern mainline at Carlsbad, New Mexico reduced El Paso's ability to deliver natural gas to California by approximately one-third. While other pipelines were able to increase deliveries and replace some of the El Paso capacity, the reduced deliveries left less gas available to inject into storage in southern California. When the storage withdrawal season began on November 1, 2000, industry sources reported that SoCal Gas' storage was at 50 percent of the normal November 1 inventory level. The November 1, 2000 monthly contract price for gas delivered into southern California closed at $5.19 per MMBtu, compared to $4.50 at Henry Hub. Less than two weeks later, an early season storm created temperatures very close to the January abnormal peak day levels estimated to occur once in 100 years. This cold spell caused SDG&E to curtail service to its electric generation customers. Daily spot prices for gas delivered to southern California rose on virtually each subsequent day to reach $18.90 by December 1, 2000.

In late 2001 and 2002 prices significantly moderated from the unprecedented levels of late 2000 and the first quarter of 2001. The market, however, remained unsettled and volatile. In October 2001, gas prices had dropped below $2 at the California border with very little premium at PG&E Citygate relative to border prices. Prices shot up to around $3 in the next month, but trended downward throughout the winter, and by February were back down to $2 or slightly less in California, as well as at Henry Hub. This behavior largely reflected the fact that winter 2001-2002 was among the warmest on record, leaving ample gas in underground storage across the country.

Market center prices had recovered to well over $3 by April 2002 and have remained strong for the remainder of the year, exceeding $4 by November 2002. Supply basin prices did not keep up with market center prices, with Canadian supplies dipping to the $1.90 range in July and August, before bouncing back over $3 in

September. Rocky Mountain prices remained well under $2 all summer, and fell to a breathtaking low of $1.20 in September 2002 – even while hurricanes in the Gulf of Mexico and the resultant off-shore well shut-ins pushed Henry Hub prices to $4 per MMBtu.

During the past winter, driven mostly by extremely cold weather in the consuming Northeast area of the country, day prices again skyrocketed to levels approaching those in 2000-2001. Hand-in-hand with rapidly depleting storage levels to meet abnormal seasonal temperatures, natural gas prices moved to new levels. In March 2003 prices were at their peak approaching $10.00/MMBtu at Henry Hub for the month. Driven by heavy draws on storage to inventory levels well below "normal," and charges that productive capacities were reaching their limits, prices have remained elevated in the $5.00 to $6.00/MMBtu level since. Most recently, driven by all time record storage injection rates, storage is taking on appearances of approaching normal inventories going into the winter of 2003-04 and prices have come down. If this trend continues to develop over the course of the next few months, as we believe it will, prices for 2003 should average somewhere over $5.00. In general, however, what we see in the natural gas market which is disconcerting to end-users and others that are dependent upon short-term gas prices, is much increased price volatility. For the longer-term the MEU Study Team projects that current price levels will moderate significantly from recent levels although not to levels seen before 2000 - 2001.

E. Price Forecast for SDG&E Service Area

The price forecast below presented is derived from NCI's 2003 Gas Price Forecast as updated in June 2003. The June 2003 Update reflects the strong impact of extraordinarily high recent aggregate price levels experienced in the first half of this year. The purpose of this Forecast is to establish reasonable estimates for generator fuel expense for existing needs and future requirements delivered into the Chula Vista service area, this supports conclusions in other portions of this Report.

Table 7 presents a 20-year gas price projection at the southern California Border with three options for pricing delivered gas to the border. These are:

- Option 1 is the delivered price within the SDG&E service area for gas purchased at the southern California border and transported to site under the currently effective blended EG rate for SoCal Gas and SDG&E of 27.47 cents.
- Option 2 is the delivered price within the SDG&E service area for gas purchased at the southern California border and transported to site using SoCal Gas and SDG&E rates that have been proposed for implementation under the CSA, but not yet approved by the Commission, of 23.94 cents.
- Option 3 is the delivered price to Otay Mesa for gas purchased at the border and transported on North Baja Pipeline to the plant at the full firm published rate of 35 cents with a 1.3% fuel retention cost included. Local pipeline costs are not included.

Table 7
Delivered Natural Gas Prices
2004-2013

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Border	5.19	4.81	4.73	4.57	4.70	4.71	4.73	4.81	4.88	4.86
Option 1. EG	5.47	5.08	5.01	4.85	4.98	4.98	5.01	5.08	5.16	5.13
Option 2. CSA	5.43	5.05	4.97	4.81	4.94	4.95	4.97	5.04	5.12	5.10
Option 3. NBP	5.55	5.16	5.09	4.93	5.06	5.06	5.09	5.16	5.24	5.21

2014-2023

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Border	4.87	4.87	4.79	4.74	4.90	5.00	5.07	5.21	5.39	5.34
Option 1. EG	5.15	5.15	5.07	5.02	5.17	5.27	5.34	5.48	5.67	5.62
Option 2. CSA	5.11	5.11	5.03	4.98	5.14	5.23	5.31	5.45	5.63	5.58
Option 3. NBP	5.23	5.23	5.15	5.10	5.25	5.35	5.43	5.57	5.75	5.70

F. Regional Issues

1. PG&E National Energy Group, Owner/Operator of North Baja Pipeline

Since the time of its default on a revolving credit facility in November 2002, PG&E NEG has negotiated with lenders to restructure the company's debts, and continues efforts to abandon, sell, and transfer assets in an effort to raise cash and reduce debt, in order to stay out of bankruptcy. Under amended agreements with the lenders, PG&E NEG must transfer its equity interest to the lenders or their designees in the Athens, Covert, Harquahala, and Millenium projects by June 30, 2003 or a default will occur.

An additional looming concern is the requirement to transfer the Lake Road and La Paloma projects to their respective lenders. PG&E NEG has secured an agreement with the lenders to extend a June 2003 deadline for transfer of these assets to September 30, 2003 or face default under the agreement. Referring to the September deadline, PG&E NEG states that it "does not currently expect to have the funds needed to fulfill its obligation to guarantee the equity commitments for these projects in the aggregate amount of $604.5 million."

Should PG&E NEG be compelled to seek protection under Chapter 11, the impact upon its pipeline operations, may possibly include:

- Sale of NBP or PGT to a financially sound institution, which if were to proceed along the lines of recent similar transactions, such as the sale of Kern River by Williams to a subsidiary of Warren Buffet's Berkshire Hathaway Group, would allow either pipeline to continue on with little or no effect upon day-to-day operations.
- PG&E NEG continues to operate its pipeline assets while in Chapter 11 proceedings.
- PG&E relinquishes the NBP operator duties to joint owner Sempra, who would be competent to assume the task.

2. Baja LNG Projects

Five LNG import and regasification projects are proposed for construction in Baja California. Sponsors include Royal/Dutch Shell in combination with Bechtel, ChevronTexaco, El Paso and Conoco/Phillips Petroleum, Sempra, Marathon Oil Company, and Mitsubishi. Completion of any of these projects would likely bring close to 1 Bcf per day in very close vicinity of the California market. The MEU Study Team understands that there is general policy support at the CPUC and CEC for addition of some new source of supply to California that does not depend on an existing interstate pipeline corridor. In addition, LNG tanks offer the benefit of providing additional gas storage. Thus, we find considerable pressure for at least one LNG project to achieve commercial operation right at about the time that our conservative projections show California may begin to need additional interstate pipeline capacity, *i.e.*, 2006/2007.[56] LNG can serve as the equivalent of interstate pipeline capacity insofar as a project located in Baja or along the California coast essentially creates a new border delivery point into the state. More importantly for market participants is the concept that LNG will not set the marginal price of gas into California. Rather, as gas prices rise as a result of near term pipeline capacity constraints and prevailing supply/production economics, LNG will be sold into the market as additional pipeline supply at the existing market-clearing price and take a netback from that. Most market participants and analysts such as the U.S. Department of Energy's Energy Information Administration cite a price of

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[56] The details of the MEU Study Team's demand projections are beyond the scope of this report. In broad terms, we grow residential demand at 1.3%, commercial at 0.3%, and industrial at 1% after economic recovery. Electric generation grows modestly at 2% per year. We disagree with projections that EG demand will decline as new, more efficient projects come on-line and in order to remain appropriately conservative with respect to gas system delivery capability, assume that economic recovery will require additional gas-fired electric generation to be added.

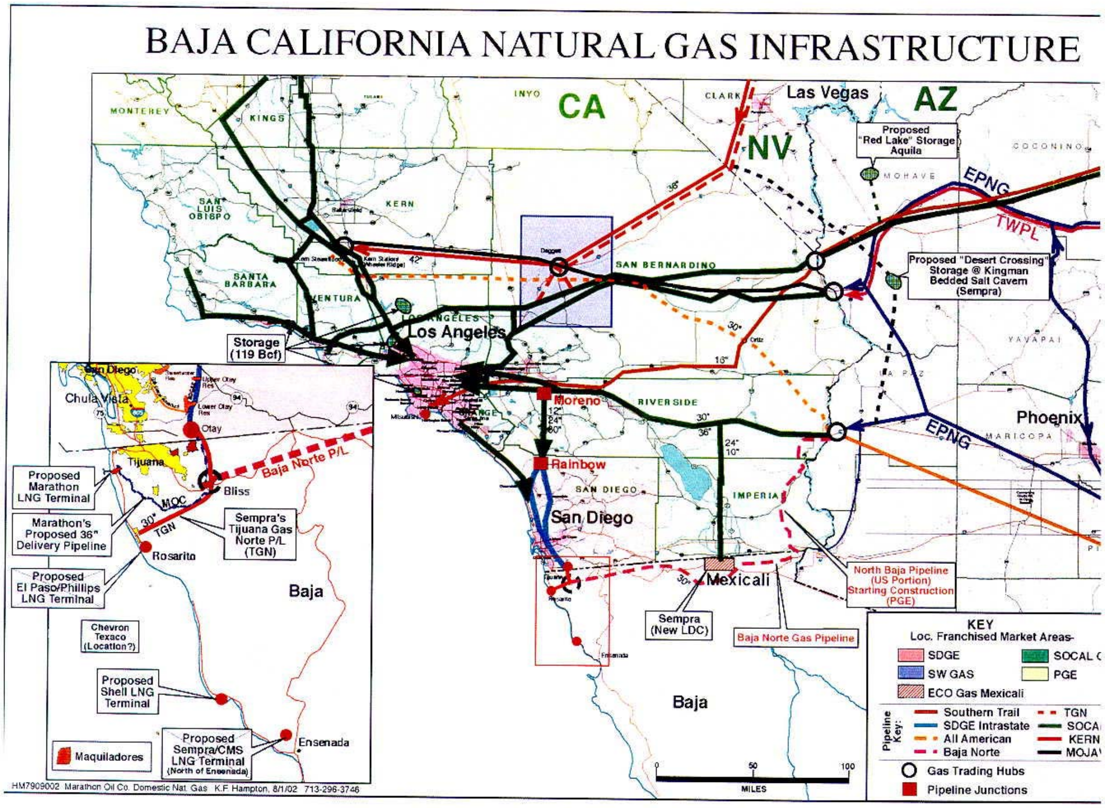
$3.50 or so per MMBtu as needed to provide an adequate producer netback to make LNG profitable. In short, construction of one LNG project is likely. Its presence may not affect prevailing market prices. It is likely to become available in the same general time frame as we would expect pipeline constraints to take hold. Table 8 below summarizes West Coast LNG project proposals and their current status and Figure 5 below indicates their proposed locations.

Table 8.
West Coast LNG Projects

Project Cost	Capacity MMcf/d	Online Date	Cost (Millions)	Status
Baja California, Mexico				- CRE permit necessary to develop/operate facilities - Environmental permits granted by Semarnat - Local governments issue land-use permits
El Paso/Conoco-Phillips, Playa de Rosarito	680	2007	$500	- Denied environmental permit due to siting problems (10/02) - Developing an "energy bridge" technology to regasify on tankers and pump gas to shore
Marathon Oil/Golar LNG/ Grupo GGS, La Joya	750	2006	$550/$1500	- First application accepted (filed 8/02) - First to receive CRE permit (5/8)
Shell Group, Costa Azul, Ensenada	1300	2007	$500-700	- Received environmental permit from Baja CA - Received Semarnat permission for $600 mm regasification project in (4/8) - Contracted for LNG feedstock for regasification plant - Letters of intent signed with potential customers for gas - Still needs license from CRE (June), approval from Costa Azul (July), Semarnat approval (soon after) of EIS for 64 km gas pipe to Tijuana

Sempra, Costa Azul, Ensenada	1000	2006	$700	- Second application accepted (filed 8/02) - Semarnat issued environmental permit (4/25) - Still needs operating permit from CRE and land use permit from Ensenada
Chevron/Texaco, Rosarito Beach	1000	2007	?	- Gravity-based structure, near Coronado Islands
California				- 4 agencies have portions of approval authority
Bechtel/Shell, Mare Island	685	2006	?	- Efforts suspended (February) - 8-month feasibility study disclosed unexpected problems
Sound Energy Solutions (Mitsubishi), Long Beach	685	2007	$400 million terminal	- Signed letter of intent with Port of Long Beach; location determined - Sakhalin Energy (unit of Mitsubishi, Mitsui, Royal Dutch/Shell) to ship gas - FERC approval needed
Crystal Energy	550			- Plans to use old oil-producing platform Grace (Chevron) off coast of Oxnard, CA as LNG receiving terminal
Calpine, N. California (Humboldt Bay)				- 250 - 300 mile gas pipeline required to connect to PG&E. - Environmentally sensitive area

Figure 5
Baja California Pipeline Infrastructure showing Proposed LNG Facilities



G. Gas Procurement Strategy

Projecting forward to the eventual adoption of the CSA, Chula Vista appears to have perhaps three distinct options for purchasing gas for delivery in the SDG&E service area. Chula Vista may either elect to purchase some percentage, if not all, of its gas requirements from supplies available at the California border. In this case Chula Vista will need to obtain transportation rights to move gas destined for Chula Vista across the SoCal Gas and SDG&E systems. Were Chula Vista to obtain rights on the SoCal Gas system, it would then necessarily select between the 100 percent reservation rate design and the 50 percent reservation/50 percent volumetric rate design at a cost of either 7.191 cents or 7.591 cents per MMBtu, respectively. In addition, Chula Vista would also need to contract for service on SDG&E's system. Although SDG&E Schedule EG currently provides for transportation of gas across both the SoCal Gas and SDG&E pipeline systems to the customer's end-use meter, the MEU Study Team's read of the CSA is that this schedule will be eliminated upon implementation of the CSA. The proposed new EG rate for SDG&E customers, that is subject to CPUC approval, is 12.53 cents per MMBtu plus 3.82 cents per MMBtu for the Interstate Transition Cost Surcharge (ITCS). This would create a total cost, for an EG customer wishing to transport gas from the California border over the SoCal Gas system and the SDG&E system to an end-user within the SDG&E service area (Chula Vista), of 23.94 cents at the 50/50 rate design or 23.54 cents at the 100 percent reservation rate.

Alternatively, with the implementation of the CSA, Chula Vista may elect to purchase gas at the SDG&E Citygate (the Rainbow compressor and meter station) from a third-party who controls access rights over SoCal Gas's system. For this option, Chula Vista would utilize Rate Schedule EG-SD (or its successor rate schedule under implementation of CSA) and would pay a transport rate of 12.53 cents plus 3.82 cents ICTS, totaling 16.35 cents. Although this transport rate is lower, Chula Vista should expect to pay a commensurately higher price for gas purchased at Rainbow rather than purchased at the border. In a related matter affecting potential delivered transport costs and regarding Calpine's Otay Mesa project, SDG&E has proposed, in its 2001 Biennial Cost Allocation Proceeding (BCAP Application, proceeding A.01-00-005, September 21, 2001), that, because of their potential to bypass the SDG&E system, Otay Mesa should be subject to a peaking service tariff much like the RLS tariff SoCal Gas uses to preclude competition. SDG&E claims its tariff is designed to "level the playing field between non-CPUC jurisdictional pipelines that offer capacity-based rates and the all-volumetric rate design charged by SDG&E. This matter is unresolved at present, the BCAP filing having been ordered dismissed in April 2003. The re-filing of the BCAP, now ordered for September 17, 2003, has potential implications for Chula Vista depending upon what SDG&E files and what the CPUC subsequently determines.

A third option for supplying the Otay Mesa location would entail purchasing gas for delivery into the Otay Mesa Import Facility off of the North Baja Pipeline. NBP currently has 123,000 MMBtu per day of unsubscribed capacity, including 64,000 MMBtu per day relinquished by PGE NEG, previously a partner with Calpine in the Otay Mesa project. Firm capacity on NBP was originally offered and fully subscribed at published rates of \$0.35 per MMBtu and 1.3% fuel retention.

IV. FINANCING OPTIONS

This Technical Appendix section provides an overview of the various types of financing mechanisms that are available to the City as a municipal issuer and provides a comparison of the differences and similarities between alternative long-term financing techniques. The following subsections are included:

A. Comparative Features of Alternative Financing Methods
B. Purpose of Financing
C. Tax-Exempt Financing Eligibility
D. Certificates of Participation
E. Commercial Paper

A. Comparative Features of Alternative Financing Methods

Financing Method Characteristics	General Obligation Bonds	Limited Obligations Bonds	Special Assessment	Certificates of Participation	Revenue Bonds
Project Financeable	Acquisition & improvements of land and buildings	Acquisition & improvements of land and buildings	Facilities of local benefit to property	Unrestricted	Revenue producing facilities
Authorization	Issuer's governing board & public election (2/3 vote)	Resolution of issue governing board and 2/3 vote	Resolution of issuer, petition of beneficiaries	Resolution of issuer governing board	Resolution of issuer governing board
Area of Authorization Jurisdiction	Boundary of issuer facilities district (flexible)	Boundary of issuer facilities district (flexible)	Flexible	N/A	Service area of issuer
Hearing Procedure	None	None	Majority protest hearing	Maybe ordinance adoption	None
Validation	None	None	None	None	None
Nature of debt service payments	Unlimited ad valorem tax	Portion of current revenues	Annual assessments based on benefits received; property taxes may not be used	Rental or installment payments	Service charges and fees from users

Source of debt service payment	Property owners in issuer jurisdiction	General revenues of issuer	Annual property assessments	General &/or enterprise revenues of issuer	Service charge and fee collections
Security	Full faith and credit	Revenue collections and coverage test	Tax collections/ Foreclosure	Lease or installment sale contract	Coverage test and contracts
Lessor/Lessee Required	No	No	No	Yes	No
Refundable	Yes	Yes	Yes	Yes	Yes
Debt Service Funds subject to Gann Limit	No	No	No	Yes	Yes
Structural Features					
Reserve Fund	No	Yes	Yes	Yes	Yes
Capitalized Interest	No	No	Yes	Yes	New enterprise only
Debt Service Coverage	No	Yes	Value/lien ratio 3:1	No	Yes
Method of Sale	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated
Advantages	Lower interest rate	No pledge of General Fund	Isolates projects	No voter approval	Higher interest rate
Disadvantages	Voter approval required	Voter approval	Limited security Higher interest rates	Highly structured Limited flexibility	Debt Service Reserve Fund

The overview above provides a broad perspective on the various financing techniques that will be available to the City. However, the ultimate method that the City chooses will be based on a number of factors.

B. Purposes of Financing

The MEU Study Team assumes that the City would use the proceeds of the financing for a number of different uses, including but not limited to: acquisition of distribution assets, construction of new plant and equipment, initial capital for power purchases, and operations and maintenance expenses among others. As outlined above, the purpose of the financing can and will affect the type of bond issue that the City can utilize to finance its various costs. In the end, the City may execute a series of different products to meet each of its various purposes.

C. Tax Exempt Eligibility

An important consideration in determining the appropriate technique is the tax-exempt eligibility of the potential financing. As all the objectives (e.g. purposes and uses of the proceeds) of the financing become clearer, the City's professional staff or advisors will have a better sense regarding the City's eligibility to issue tax-exempt bonds.

There are specific limitations on the use of traditional public agency, tax-exempt, revenue or obligation bonds. If a City wants to issue revenue bonds to finance the acquisition, construction or improvement of any enterprise, after submitting the question to its electors and receiving a favorable majority vote, the City may proceed to undertake and finance the project.[57] However, revenue bond law does not authorize a local agency to borrow money and issue bonds for systems, plants works, or undertakings for the distribution of electric energy for lighting, heating, and power for public or private uses.[58] Further, Internal Revenue Code Section 141 (d) treats bonds issued to finance the acquisition by a governmental unit of "nongovernmental output property" (includes electric distribution facilities) as taxable, private activity bonds. No other exemptions from this stipulation (Sections 141.d.3 and 142.f) provide for tax-exempt bonds to be issued for this purpose. Section 141 (d) was aimed at preventing use of tax-exempt financing for public takeovers of private utilities.

D. Certificates of Participation

Certificates of Participation (COPs) are a financing mechanism widely used by municipalities to finance property and equipment. Municipalities generally choose this type of financing because they are not strictly considered debt obligations. The certificates are typically a type of government lease-backed financing.

Lease-backed financing takes the form, but generally not the substance, of a lease between a lessor and a lessee. In reality, it is much like an installment purchase agreement. The lessee (the ultimate buyer, often a government agency) purchases specified property from the lessor in installments over an established period by making lease payments. Once all lease payments are made, the lessee obtains full ownership rights to the property for a nominal sum.

The financing adopts the formal aspects of a lease agreement primarily for reasons relating to state debt limitations. Normally voter approval is required in most states before a municipality can incur new debt. Lease-backed financing, however, is not classified as "debt" under most debt limitation laws, providing certain conditions are met. Therefore, this type of lease financing enables an issuer to issue debt without the restrictions of voter approval or limitations set under debt capacity rules.

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[57] Cal. Govt. Code § 50798.4.

[58] Cal. Gov. Code §§ 54301 and 54310.

COPs add to lease-backed financing some of the desirable features of bonds, especially liquidity. In a COP arrangement, investors buy certificates that entitle them to receive participation or share in the lease payments from a particular project. The lease payments are passed through the lessor to the certificate holder with the tax advantages intact.

There are a number of threshold requirements that must be met in this type of financing to qualify. Once the City has a better perspective of how the financing should be structured, it would be appropriate to determine eligibility to execute a COP or in broad terms a lease-revenue financing.

E. Commercial Paper

Another financing tool used by issuers as a short-term financing mechanism is commercial paper, which combines financial management techniques used by corporations with the borrowing authority granted to public entities. Due to the nature of this type of financing, voter approval is not typically required.

Commercial paper may be used in place of, or combined with, short-term notes to provide short-term borrowing to cover cash-flow deficits. Commercial paper is secured by pledged revenues and a revolving credit agreement with a commercial bank. Commercial paper must mature between one and 270 days; however, it can be rolled over for continuous time periods of no more than 270 days.

Advantages of issuing Commercial Paper:

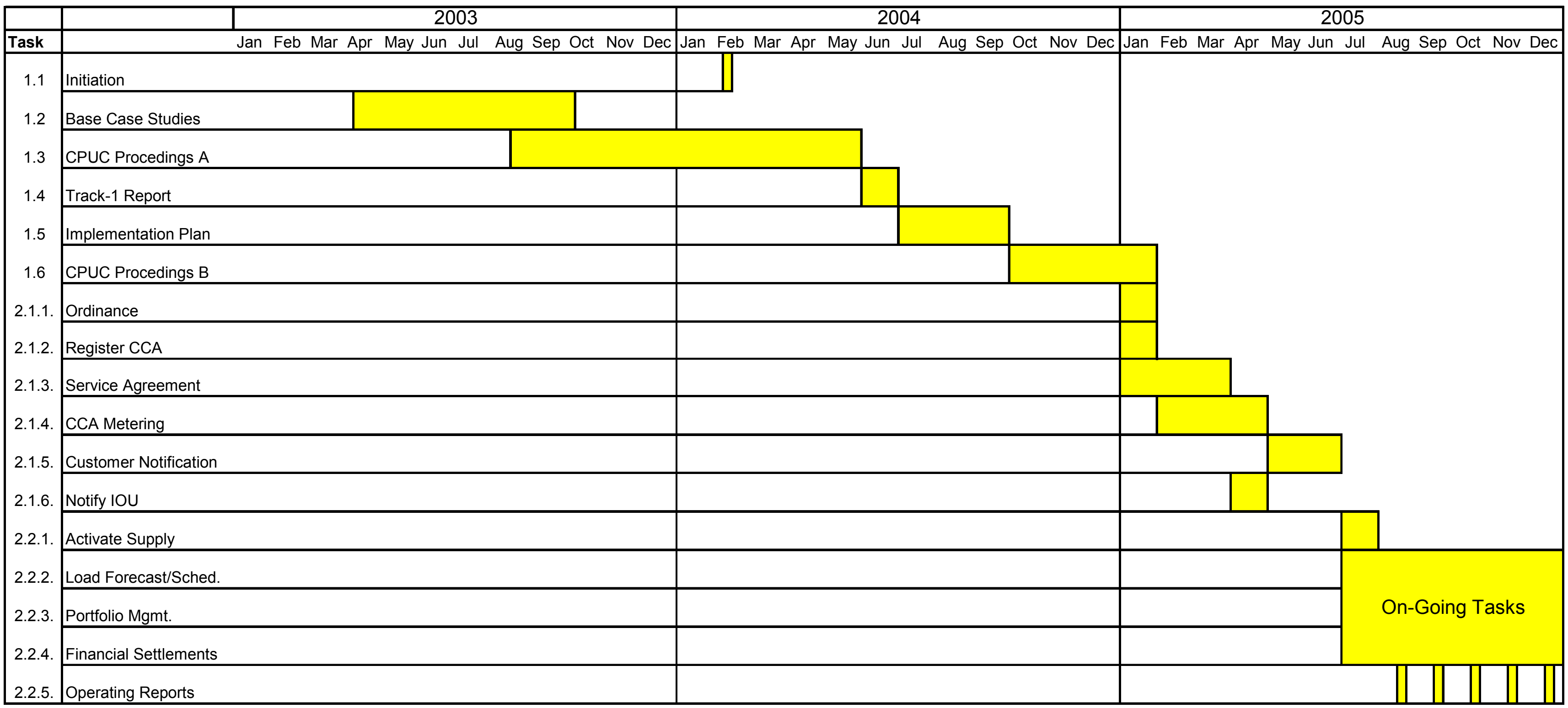
- Excellent short-term interest rates
- Flexibility to repay principal on Issuer's schedule
- No bond election is required (i.e., no voter approval)
- Interest earned on the investment of the proceeds may be used for any designated purpose

V. IMPLEMENTATION SCHEDULES

This Technical Appendix section contains Gantt chart projections for Implementation Schedules for MEU structure options as described in Report Section III. The following subsections are included:

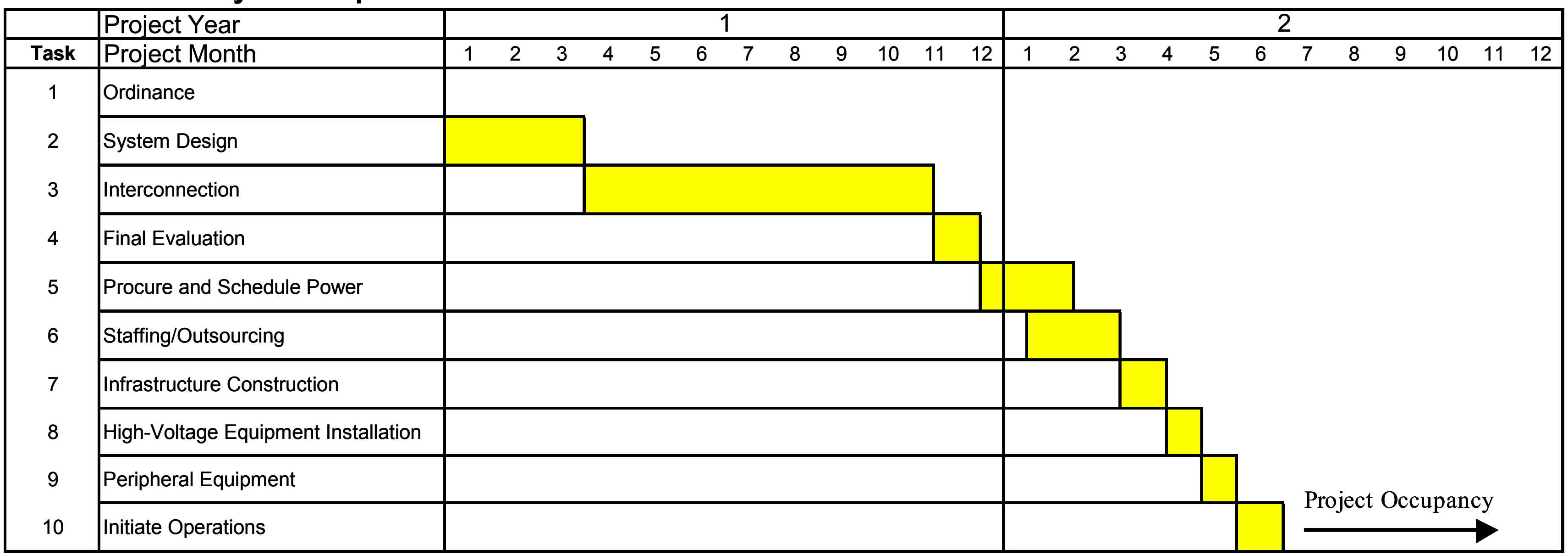
A. CCA - Implementation Schedule
B. Greenfield Implementation Schedule
C. MDU Implementation Schedule

A. CCA - Implementation Schedule

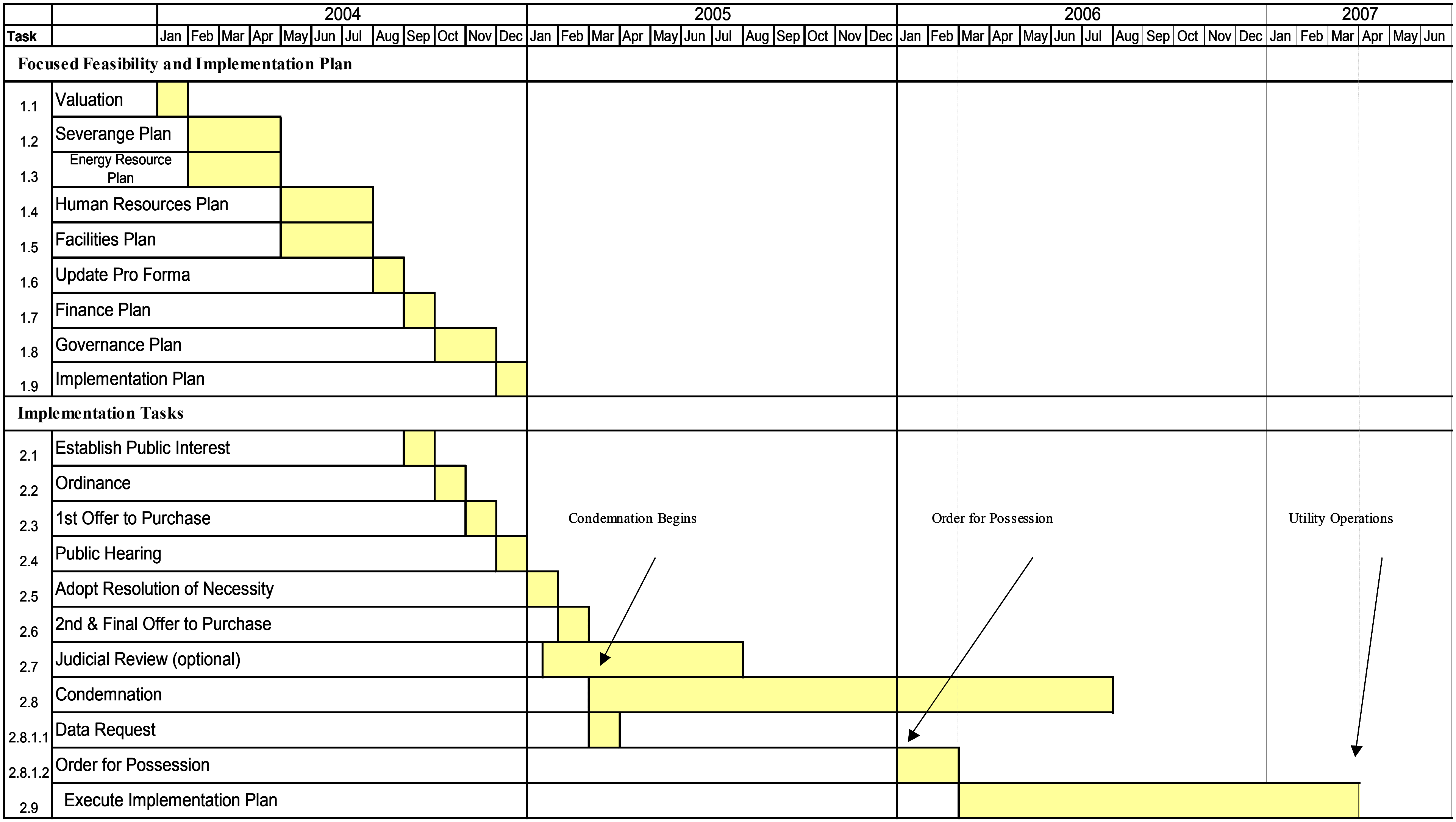


B. Greenfield Implementation Schedule

Greenfield Utility Development



C. MDU Implementation Schedule



VI. OPERATING AND MAINTENANCE EXPENSE

This Technical Appendix contains analyses supporting operating and maintenance expense (O&M) assumptions applied in the cost-benefit financial analyses. The section contains the following:

A. National Public Utility O&M Benchmarking
B. California Public Utility Statistics Used to Select a Targeted Benchmarking Panel of Four Municipal Utilities
C. Targeted O&M Expenses Benchmarking Panel
D. Human Resources

A. National Public Utility O&M Benchmarking

Operation and Maintenance Expense Benchmarking (Source: 2000 EIA Form 412)

Total operating expense is the sample strata average - Constituent elements are normalized to group averages less trans. Total operating expense as reported in EIA Form 412 is consistent with cost of service studies for like sized utilities. However, the constituent" down-parts" (dist., cust services, a&g) reflect inconsistent reporting treatment - Their % contributions to strata total O&M have been normalized (averaged across strata). Trans: Most public power entities examined do not have trans assets, were rarely reported and are addressed as part of the "delivered" energy cost. Customer accounting, customer service and sales costs are combined under Customer Service. O&M (Dist/Cust Srvc/A&G) is treated as a fixed (versus variable) cost (does not vary with energy volume) and is allocated on a per customer basis.

Benchmark Panel Selection			Operating and Maintenacne Cost per Customer ($)			
Strata	Panel Counterparts	Accts	Total Strata Avg.	Dist. Norm. %	Cust. Srvc Norm. %	A&G Norm. %
1	Anaheim	109,223				
	Colorado Springs	179,592				
	Clark County PUD	151,555	235	110	45	80
	City of Tacoma	147,819				
	MID	94,472				
2	Blue Ridge Elec Member	61,663				
	Blue Ridge Elec Coop	54,576				
	Brunswick Electric Member	60,212	301	141	57	102
	Rutherford Electric Member	58,417				
	Turlock	66,642				
3	Alameda	32,595				
	Loveland	23,932				
	Palo Alto	27,750	309	145	59	105
	Redding	38,982				
4	Columbia River PUD	11,982				
	Emerald PUD	17,167				
	Gallup	10,518	312	147	59	106
	Mesa	15,966				
	Franklin County PUD	18,465				
5	Los Alamos	8,114				
	N. Wasco Co. PUD	9,235				
	Overton	8,401				
	Pend Oreille County PUD	7,590	366	172	70	124
	Springville	7,564				
6	Clatskanie PUD	3,854				
	Pinal County Electric	2,803				
	Anza Electric Coop	3,522	565.59	265.83	107.46	192.30
	Wasco Electric Coop	4,381				

B. California Public Utility Statistics

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Data Item	Chula Vista Est. 2004	Year	Anaheim	Burbank	Glendale	Pasadena
		Utility Data Source: EIA Form 861, Schedule IV, Line 1b, Column g				
MWhs	738,978	2000	2,605,405	1,055,881	1,094,322	1,171,759
		1999	2,416,302	1,029,003	1,071,277	1,129,383
		1998	2,374,594	1,011,533	1,054,015	1,126,441
		1997	2,469,012	1,036,915	1,058,469	1,147,194
		1996	2,285,932	984,919	1,037,911	1,103,376
		1995	2,245,057	950,544	1,021,426	1,149,749
Customers	78,998	2000	109,223	51,701	86,534	58,390
		1999	105,755	51,488	83,100	58,378
		1998	107,161	50,600	82,979	58,358
		1997	106,046	50,664	82,775	57,965
		1996	105,363	50,535	82,634	57,975
		1995	104,299	50,398	82,496	57,807
Distribution Plant $	$170,000,000	2000	$238,099,000	$108,255,000	$130,678,000	$172,066,431
		1999	$232,027,000		$130,270,000	$165,688,291
		1998	$222,089,000	$93,087,000	$121,278,000	$160,002,509
		1997	$208,223,000	$90,347,000	$116,762,000	$155,862,488
		1996	$188,818,000	$86,656,000	$116,105,000	$146,435,329
		1995	$170,334,000	$83,083,000	$113,506,000	$141,419,233
Operating Revenue	131,879,553	2000	$279,457,000	$110,274,000	$128,998,000	$170,825,966
		1999	$254,521,000		$135,166,000	$136,500,546
		1998	$244,239,000	$98,446,000	$125,399,000	$125,477,726
		1997	$244,195,000	$97,847,000	$122,098,000	$114,079,866
		1996	$246,479,000	$90,731,000	$98,020,000	$106,712,184
		1995	$240,175,000	$93,766,000	$96,192,000	$109,865,726
FTE	239		215	266	305	201
FTE/1000 Customers	3.02		1.97	5.14	3.52	3.44

B. California Public Utility Statistics

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ata Item	Chula Vista Est. 2004	Year	TID	Alameda	Azusa	Colton
		Utility Data Source: EIA Form 861, Schedule IV, Line 1b, Column g				
MWhs	738,978	2000	1,451,488	374,217	237,852	297,536
		1999	1,415,162	371,326	233,213	266,108
		1998	1,347,431	359,667	214,593	249,907
		1997	1,364,344	362,556	210,760	212,391
		1996	1,310,843	405,275	205,918	224,529
		1995	1,221,610	461,698	201,871	213,041
Customers	78,998	2000	66,642	32,595	14,781	17,608
		1999	66,456	32,569	14,549	16,893
		1998	65,380	32,385	14,656	16,574
		1997	64,877	32,482	14,492	15,932
		1996	64,543	31,704	14,492	15,932
		1995	63,736	31,445	14,350	16,480
Distribution Plant $	$170,000,000	2000	$115,269,874	$44,975,731	$18,704,738	
		1999	$106,585,935	$43,549,314	$19,436,422	
		1998	$102,891,310	$42,342,106	$18,950,666	
		1997	$98,260,623	$41,683,944	$18,904,851	
		1996	$95,226,472	$39,819,173	$18,038,111	
		1995	$90,007,941	$37,817,722	$16,889,408	
Operating Revenue	131,879,553	2000	$189,995,162	$39,329,340	$31,632,053	$29,109,961
		1999	$109,807,674	$39,185,527	$30,117,994	$29,045,608
		1998	$106,559,977	$37,643,234	$25,318,749	$26,095,969
		1997	$106,713,200	$39,571,638	$23,342,520	$26,186,184
		1996	$105,114,514	$43,835,353	$22,692,637	$24,669,075
		1995	$101,266,868	$46,935,386	$22,329,186	$24,239,747
FTE	239		417	87	18	52
FTE/1000 Customers	3.02		6.26	2.67	1.22	2.95

B. California Public Utility Statistics

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Data Item	Chula Vista Est. 2004	Year	IID	Lassen	Lodi	LADWP
		Utility Data Source: EIA Form 861, Schedule IV, Line 1b, Column g				
hs	738,978	2000	2,556,914	141,199	406,185	21,124,510
		1999	2,384,949	136,909	391,276	20,056,691
		1998	2,353,858	135,243	376,183	21,696,008
		1997	2,412,333	133,952	367,931	24,341,684
		1996	2,382,446	131,751	364,062	21,341,953
		1995	2,301,113	126,233	348,210	21,063,474
tomers	78,998	2000	101,574	11,006	24,764	1,459,153
		1999	93,486	10,162	23,776	1,385,396
		1998	90,652	10,053	23,105	1,374,424
		1997	88,457	9,963	22,723	1,455,098
		1996	86,685	9,797	22,586	1,347,557
		1995	84,869	9,670	22,352	1,343,482
tribution nt $	$170,000,000	2000	$377,129,433		$27,671,059	$3,469,366,891
		1999	$338,550,477		$23,081,159	$3,351,080,932
		1998	$313,510,753			$3,219,452,080
		1997	$288,589,277	$18,306,326		$3,111,690,450
		1996	$265,790,743	$17,107,382	$15,648,314	$3,020,680,000
		1995	$250,758,924	$16,904,037	$15,090,653	$2,893,653,785
perating	131,879,553	2000	$240,283,203		$38,268,000	$2,396,136,690
		1999	$213,014,046		$37,222,762	$2,203,363,903
		1998	$209,894,855			$2,162,916,635
		1997	$208,157,993	$12,802,890		$2,017,065,508
		1996	$202,299,793	$14,050,111	$34,925,892	$1,946,851,000
		1995	$192,067,438	$14,509,706	$34,047,610	$1,972,786,346
E	239		376	17	44	4,993
TE/1000 Customers	3.02		3.70	1.54	1.78	3.42

B. California Public Utility Statistics

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Data Item	Chula Vista Est. 2004	Year	MID	Palo Alto	Redding	Riverside
		Utility Data Source: EIA Form 861, Schedule IV, Line 1b, Column g				
MWhs	738,978	2000	2,257,435	1,125,717	674,571	1,795,914
		1999	2,164,620	1,124,025	683,493	1,647,509
		1998	2,126,758	1,121,450	676,061	1,631,951
		1997	1,998,256	1,077,181	699,722	1,652,950
		1996	1,937,605	1,066,125	713,451	1,637,156
		1995	1,847,637	1,051,633	680,225	1,562,088
Customers	78,998	2000	94,472	27,750	38,982	93,940
		1999	92,229	27,723	38,295	92,644
		1998	91,351	27,638	37,852	91,343
		1997	90,201	27,575	37,501	89,943
		1996	89,934	27,527	36,982	89,588
		1995	89,111	27,461	36,700	88,286
Distribution Plant $	$170,000,000	2000	$150,221,262	$154,628,000	$135,687,603	$201,338,954
		1999	$143,371,838	$149,735,000		$195,255,548
		1998	$137,393,835	$145,727,000		$186,913,213
		1997	$128,485,051	$140,751,000		$179,214,906
		1996	$126,142,937	$79,703,000		$151,302,958
		1995	$116,542,420	$127,378,000		$145,781,418
Operating Revenue	131,879,553	2000	$218,147,944	$66,591,000	$116,932,774	$188,639,011
		1999	$150,897,979	$78,970,000	$105,358,913	$172,133,726
		1998	$145,903,555	$81,142,000	$102,952,139	$176,452,787
		1997	$139,820,064	$70,171,000	$89,551,981	$175,650,568
		1996	$137,348,625	$62,988,000	$72,620,280	$164,821,455
		1995	$130,272,297	$64,974,000	$64,627,172	$155,897,535
FTE	239		281	104	102	241
FTE/1000 Customers	3.02		2.97	3.75	2.62	2.57

B. California Public Utility Statistics

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Data Item	Chula Vista Est. 2004	Year	Roseville	SMUD	Santa Clara	Average
		Utility Data Source: EIA Form 861, Schedule IV, Line 1b, Column g				
MWhs	738,978	2000	880,535	9,764,870	2,630,930	
		1999	819,570	9,429,523	2,491,714	
		1998	802,873	9,138,407	2,506,452	
		1997	749,781	8,975,951	2,458,081	
		1996	693,468	8,889,261	2,340,285	
		1995	626,179	8,458,888	2,196,020	
Customers	78,998	2000	36,962	512,216	48,108	
		1999	36,243	503,684	47,524	
		1998	34,095	495,167	46,483	
		1997	32,386	488,812	45,980	
		1996	29,855	483,661	45,703	
		1995	28,066	478,119	45,718	
Distribution Plant $	$170,000,000	2000	$150,049,710	$821,983,382		
		1999	$131,768,603	$797,520,587		
		1998	$122,021,574	$787,292,174		
		1997	$107,333,896	$772,748,999		
		1996	$97,591,619	$736,398,158		
		1995	$89,005,659	$714,414,106		
Operating Revenue	131,879,553	2000	$68,976,482	$967,615,579	$187,359,438	
		1999	$63,133,281	$775,496,370	$193,285,316	
		1998	$57,313,353	$765,680,805	$184,374,153	
		1997	$56,807,530	$714,158,755		
		1996	$51,582,265	$670,284,045	$183,901,001	
		1995	$47,464,581	$613,896,059	$157,989,707	
FTE	239		66	1,920	116	
FTE/1000 Customers	3.02		1.79	3.75	2.41	3.02

C. Targeted O&M Expenses Benchmarking Panel

The following table benchmarks costs for providing operation, maintenance, and administrative services for similar sized utilities. The table illustrates, for four local governmental-owned utilities in California, the number of full-time employees (FTE), distribution operation and maintenance costs, customer service and administrative costs, total number of customers, total retail sales, annual O&M costs per customer, and annual O&M costs per kWh. These utilities where selected because they have near the same number of customers that the City would likely have if it were to serve all City loads.

Burbank	**2001**	**2000**	**1999**	**1998**	**Average**
FTE	276	266	n/a	251	**264**
Distribution O&M	11,823,000	11,249,000	n/a	6,584,000	**9,885,333**
Customer Service O&M	0	0	n/a	0	**0**
Customer Account Expenses	0	2,017,000	n/a	2,819,000	**1,612,000**
Administrative and General O&M	8,521,000	6,368,025	n/a	5,254,000	**6,714,342**
Total O&M	**20,344,000**	**19,634,025**	**n/a**	**14,657,000**	**18,211,675**
Total Customers	51,335	51,701	51,488	50,600	**51,281**
Total MWH Sold	1,064,983	1,055,881	1,029,003	1,011,533	**1,040,350**
O&M per Customer	396.30	379.76	n/a	289.66	**355.24**
O&M per kWh	0.0191	0.0186	n/a	0.0145	**0.0174**
Glendale	**2001**	**2000**	**1999**	**1998**	**Average**
FTE	354	305	259	259	**294**
Distribution O&M	11,549,000	8,638,000	6,528,000	5,534,000	**8,062,250**
Customer Service O&M	1,533,000	n/a	n/a	n/a	**1,533,000**
Customer Account Expenses	0	4,147,000	3,602,000	2,796,000	**2,636,250**
Administrative and General O&M	1,634,000	1,634,000	10,020,000	9,120,000	**5,602,000**
Total O&M	**14,716,000**	**14,419,000**	**20,150,000**	**17,450,000**	**16,683,750**
Total Customers	83,489	86,534	83,100	82,979	**84,026**
Total MWH Sold	1,084,715	1,094,322	1,071,277	1,054,015	**1,076,082**
O&M per Customer	176.26	166.63	242.48	210.29	**198.92**
O&M per kWh	0.0136	0.0132	0.0188	0.0166	**0.0155**
Pasadena	**2001**	**2000**	**1999**	**1998**	**Average**
FTE	186	201	188	214	**197**
Distribution O&M	5,423,241	4,663,422	4,005,884	4,512,730	**4,651,319**
Customer Service O&M	621,714	672,648	563,889	751,698	**652,487**
Customer Account Expenses	0	1,894,634	2,127,411	2,258,965	**1,570,253**
Administrative and General O&M	7,429,427	6,287,902	7,074,260	8,079,146	**7,217,684**
Total O&M	**13,474,382**	**13,518,606**	**13,771,444**	**15,602,539**	**14,091,743**
Total Customers	59,354	58,390	58,378	58,358	**58,620**
Total MWH Sold	1,100,721	1,171,759	1,129,383	1,126,441	**1,132,076**
O&M per Customer	227.02	231.52	235.90	267.36	**240.45**
O&M per kWh	0.0122	0.0115	0.0122	0.0139	**0.0125**

Turlock ID	2001	2000	1999	1998	Average
FTE	413	417	442	436	**427**
Distribution O&M	8,127,495	7,252,052	6,371,379	6,783,935	**7,133,715**
Customer Service O&M	0	0	0	0	**0**
Customer Account Expenses	0	2,351,283	2,152,845	2,291,882	**1,699,003**
Administrative and General O&M	9,505,492	12,730,195	9,187,869	8,489,695	**9,978,313**
Total O&M	**17,632,987**	**22,333,530**	**17,712,093**	**17,565,512**	**18,811,031**
Total Customers	73,401	66,642	66,456	65,380	**67,970**
Total MWH Sold	1,451,272	1,451,488	1,415,162	1,347,431	**1,416,338**
O&M per Customer	240.23	335.13	266.52	268.67	**277.64**
O&M per kWh	0.0122	0.0154	0.0125	0.0130	**0.0133**

D. Human Resources

1. Portfolio Operations and Scheduling - CCA

Portfolio Operations and Scheduling Costs Worksheet
Medium Size Municipal Electric Utility (50,000 to 90,000 Customers)

A. Labor Costs

Function	FTE	Salaries	Benefits	Annual Cost	Potential Outsourcing
Rates/Forecasting	3	$ 70,000	$ 9,100	$ 237,300	Consultant
Resource Planning	2	$ 70,000	$ 10,500	$ 161,000	Consultant
Trading/Risk Management	4	$ 80,000	$ 12,000	$ 368,000	Power Marketer
Wholesale Settlements	2	$ 60,000	$ 9,000	$ 138,000	Scheduling Coordinator
Pre-Schedulers	2	$ 60,000	$ 9,000	$ 138,000	Power Marketer
Real Time Desk	6	$ 60,000	$ 9,000	$ 414,000	Scheduling Coordinator
Credit	1	$ 70,000	$ 10,500	$ 80,500	Consultant
Management	3	$ 95,000	$ 14,250	$ 327,750	
IOU Transactions/Audits	2	$ 60,000	$ 9,000	$ 138,000	Consultant
IT Support	1	$ 70,000	$ 10,500	$ 80,500	Scheduling Coordinator
Total Labor	26			$ 2,083,050	

B. Administrative and General Costs

Loading Rate	55%	
Direct Labor Costs	$ 2,083,050	
A&G and Common Costs		$ 1,145,678

C. Total Costs Summary

Labor	$ 2,083,050
Overheads	$ 1,145,678
Total	$ 3,228,728

2. Portfolio Operations - Greenfield (In-House Stand-Alone labor)

Minimum Portfolio Operations - Greenfield

Settlements	1
Procurement/Contracts	1
Rates	1
Credit	1
Management	1
	5

FTE Average Annual Salary	$69,500
Fringe Benefits (15%)	$10,300
Annual Labor Estimates	$399,000

3. Municipal Distribution Utility Human Resources Requirements

Director & Support Staff
3

Finance Mgr. & Supt Staff
3

Distribution Engineering & Operations

Manager & Support Staff	2
Substations (Supervisors and Tech.s)	19
Dispatch (SCADA)	3
Operators	12
Construction	4
Troubleshooters	5
Materials Techs	2
Line Crew and Foremen	32
Metering	
Electronics Techs	4
Service Planning (New Services)	1
Engineering Techs	5
Drafting Techs	4
Engineering	1
Power Engineers	5
Computer Maintenance	1
	100

Customer & Energy Services

Customer & Energy Services Mgr.	1
ESRs	4
Field Services	2
Meter Readers	14
Credit & Collections	1
Accounting	3
Call Ctr CSRs	8
Billing Clerks	5
	38

Power Operations Group

Portfolio Operations	
Management	3
Rates/Forecasting	3
Resource Planning	2
Trading/Risk Management	4
Wholesale Settlements	2
Pre-Schedulers	2
Real Time Desk	6
Credit	1
IOU Transactions/Audits	2
IT Support	1
Power Production	
Power Plant Op.s	0
	26

Total MDU Staff 170

APPENDIX D

SAN DIEGO GAS & ELECTRIC COMPANY

WHOLESALE DISTRIBUTION OPEN ACCESS TARIFF

SAN DIEGO GAS & ELECTRIC COMPANY

WHOLESALE DISTRIBUTION OPEN ACCESS TARIFF

TABLE OF CONTENTS

I. GENERAL SERVICE PROVISIONS

Preamble

The Distribution Provider will provide Distribution Service to Distribution Customers pursuant to the applicable terms and conditions of this Tariff. Distribution Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery. The Tariff must be used in conjunction with the Independent System Operator's and Transmission Owner's Tariffs.

1 Definitions: Capitalized terms used in this Wholesale Distribution Tariff shall have the meaning set out below unless otherwise stated in this Tariff.

1.1 Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 Application: A request by an Eligible Customer for Distribution Service pursuant to the provisions of this Tariff.

1.3 CIAC: CIAC or Contribution In-Aid-of Construction is all property, including money, received by SDG&E from an Eligible Customer to provide for the installation, improvement, replacement, or expansion of SDG&E distribution facilities.

1.4 Commission: The Federal Energy Regulatory Commission.

1.5 Completed Application: An Application that satisfies all of the information and other requirements of this Tariff, including any required deposit.

1.6 Curtailment: A reduction in Distribution Service in response to a capacity shortage as a result of system reliability conditions.

1.7 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.8 Designated Agent: Any entity that performs actions or functions on behalf of the Distribution Provider, an Eligible Customer, or the Distribution Customer required under the Tariff.

1.9 Direct Assignment Facilities: Distribution Facilities or portions of facilities that are constructed by the Distribution Provider for the sole use/benefit of a particular Distribution Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Distribution Customer and shall be subject to Commission approval.

1.10 Distribution Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Distribution Provider files with the Commission a proposed unexecuted Service Agreement.

1.11 Distribution Facilities: The facilities of the Distribution Provider as defined in the Commission's order in Docket No. EL96-98-000 dated October 30, 1996. This equipment will include electrical equipment consisting of poles, conduit, splice boxes, conductors, transformers and devices at less than 50kv.

1.12 Distribution Provider: San Diego Gas & Electric Company ("SDG&E") or its Designated Agent, that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides Distribution Service under this Tariff.

1.13 Distribution Service: The transporting of electric power over and through, Distribution Facilities from the Point(s) of Receipt to the Point(s) of Delivery under this Tariff.

1.14 Eligible Customer: Any electric utility (including the Distribution Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to Distribution Service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Distribution Provider offer the Distribution Service, or pursuant to a voluntary offer of such service by the Distribution Provider.

1.15 Facilities Study: An engineering study conducted by the Distribution Provider to determine the required modifications to the Distribution Provider's Distribution System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.16 Generation: The capacity and output of any generating facility connected to SDG&E's Distribution Facilities.

1.17 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.18 ISO: The Independent System Operator approved by the Commission to operate the interconnected transmission system in California.

1.19 ITCC: ITCC or the Income Tax Component of Contributions is the Federal and State tax the Distribution Provider pays on income received as a CIAC.

1.20 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part II of the Tariff.

1.21 Native Load Customers: The wholesale and retail power customers of the Distribution Provider on whose behalf the Distribution Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Distribution Provider's system to meet the reliable electric needs of such customers.

1.22 Parties: The Distribution Provider and the Distribution Customer receiving service under the Tariff.

1.23 Point(s) of Delivery: Point(s) on the Distribution Facilities where capacity and energy transmitted by the Distribution Provider will be made available to the Receiving Party under this Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Distribution Service.

1.24 Point(s) of Receipt: Point(s) of interconnection on the Distribution Provider's Distribution Facilities System where capacity and energy will be made available to the Distribution Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.25 Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.26 Receiving Party: The entity receiving the capacity and energy transmitted by the Distribution Provider to Point(s) of Delivery.

1.27 Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.28 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Distribution Customer and the Distribution Provider for service under this Tariff.

1.29 Service Commencement Date: The date the Distribution Provider begins to provide service pursuant to the terms of an executed

Service Agreement, or the date the Distribution Provider begins to provide service in accordance with Section 13.2 under this Tariff.

1.30 System Impact Study: An assessment by the Distribution Provider of (i) the adequacy of the Distribution Facilities to accommodate a request for Distribution Service and (ii) whether any additional costs may be incurred in order to provide Distribution Service. The System Impact Study shall identify any system constraints and redispatch options and Direct Assignment Facilities required to provide the requested service.

1.31 Third-Party Sale: Any sale for resale in interstate commerce to a Power Purchaser.

1.32 Transmission System: The 69kV and above facilities owned by the Distribution Provider and controlled by the ISO that are used to provide transmission service under the ISO Tariff.

2. Ancillary Services

Ancillary Services, although required for Transmission Service, are not available in or through this Tariff. The Distribution Service offer is conditioned on the Distribution Customer having retained necessary Ancillary Services under other Commission approved tariffs.

3 Local Furnishing Bonds

3.1 Distribution Providers That Own Facilities Financed by Local Furnishing Bonds: This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this Tariff, the

Distribution Provider shall not be required to provide Distribution service to any Eligible Customer pursuant to this Tariff if the provision of such Distribution service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Distribution Provider's facilities that would be used in providing such transmission service.

3.2 Alternative Procedures for Requesting Distribution Service:

(i) If the Distribution Provider determines that the provision of Distribution service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such Distribution service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same Distribution service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Distribution Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Distribution Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Distribution Provider shall be required to provide the requested Distribution service in accordance with the terms and conditions of this Tariff.

4 Reciprocity

A Distribution Customer receiving Distribution service under this Tariff agrees to provide comparable distribution service that it is capable of providing to the Distribution Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Distribution Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Distribution Customer's corporate affiliates. A Distribution Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable distribution service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Distribution Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Distribution Customer's corporate affiliates.

This reciprocity requirement applies not only to the Distribution Customer that obtains Distribution service under the Tariff, but also to all parties to a transaction that involves the use of Distribution Service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates distribution facilities that uses an intermediary, such as a power marketer, to request Distribution Service under the Tariff. If the Distribution Customer does not own, control or operate transmission or distribution facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

5 Billing and Payment

5.1 Billing Procedure: Within a reasonable time after the first day of each month, the Distribution Provider shall submit an invoice to the Distribution Customer for the charges for all services furnished under this Tariff during the preceding month. The invoice shall be paid by the Distribution Customer within twenty (20) days of receipt. All payments shall be made in immediately available U.S. funds payable to the Distribution Provider. If payment is by wire transfer payment shall be to a bank named by the Distribution Provider and to an account number in the name of the Distribution Provider.

5.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Distribution Provider.

5.3 Customer Default: In the event the Distribution Customer fails, for any reason other than a billing dispute as described below, to make payment to the Distribution Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Distribution Provider notifies the Distribution Customer to cure such failure, a default by the Distribution Customer shall be deemed to exist. Upon the occurrence of a default, the Distribution Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Distribution Provider and the Distribution Customer, the Distribution Provider will continue to provide service under the Service Agreement as long as the Distribution Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Distribution Customer fails to meet these two requirements for continuation of service, then the Distribution Provider may provide notice to the Distribution Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

6 Accounting for the Distribution Provider's Use of the Tariff. The Distribution Provider shall record the following amounts, as outlined below.

6.1 Distribution Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Distribution Service when making Third-Party Sales under Part II of the Tariff.

6.2 Study Costs and Revenues: Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Distribution Provider conducts to determine if it must construct new Distribution Facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Distribution Customer's billing under the Tariff

7 Regulatory Filings

Nothing contained in this Tariff or any Service Agreement, except to the extent provided in such Agreement, shall be construed as affecting in any way the right of the Distribution Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in this Tariff or any Service Agreement, except to the extent provided in such Agreement, shall be construed as affecting in any way the ability of any Party receiving service under this Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

8 Force Majeure and Indemnification

8.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Distribution Provider nor the Distribution Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

8.2 Indemnification: The Distribution Customer shall at all times indemnify, defend, and save the Distribution Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Distribution Provider's performance of its obligations under this Tariff on behalf of the Distribution Customer, except in cases of negligence or intentional wrongdoing by the Distribution Provider.

9 Creditworthiness

For the purpose of determining the ability of the Distribution Customer to meet its obligations related to service hereunder, the Distribution Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Distribution Provider may require the Distribution Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under this Tariff, or an alternative form of security proposed by the Distribution Customer and acceptable to the Distribution Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Distribution Provider against the risk of non-payment.

10 Dispute Resolution Procedures

10.1 Internal Dispute Resolution Procedures: Any dispute between a Distribution Customer and the Distribution Provider involving Distribution Service under this Tariff (excluding applications for rate changes or other changes to this Tariff, or to any Service Agreement entered into under this Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Distribution Provider and a senior representative of the Distribution Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

10.2 External Arbitration Procedures: Any arbitration initiated under this Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission, distribution and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

10.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Tariff and any Service Agreement entered into under this Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

10.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

10.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. DISTRIBUTION SERVICE

11. Applicability

Distribution Service is available to new Distribution Customers which request Distribution Service, and existing Distribution Customers which request new Distribution Service for service to additional Point(s) of Receipt or Delivery. This Tariff is not for the purpose of retail service to a Native Load Customers; such service is provided for and must be taken under CPUC retail and direct access tariffs.

12 Nature of Distribution Service

12.1 Term: The minimum term of Point-To-Point Distribution Service shall be one day and the maximum term shall be as specified in the Service Agreement.

12.2 Service Priority: Distribution Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Distribution Customer has submitted a Completed Application. Distribution Service will be conditional based upon the length of the requested transaction. If the Distribution Facilities becomes oversubscribed, requests for longer term service may preempt requests for shorter term service. Such requests will be accepted by the Distribution Provider up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional service deadline, if the Distribution Facilities are insufficient to satisfy all Applications, an Eligible Customer with a service request for shorter term service has the right of first refusal to match any longer term request for service before losing its service priority. A longer term competing request for Distribution Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours from being notified by the Distribution Provider of a longer-term competing request for Distribution Service. After the conditional service deadline Distribution Service will commence pursuant to this Tariff.

12.3 Use of Distribution Service by the Distribution Provider: The Distribution Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in Federal Register] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Distribution Provider will maintain separate accounting, pursuant to Section 6, for any use of the Distribution Service to make Third-Party Sales.

12.4 Service Agreements: The Distribution Provider shall offer a standard form Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Distribution Service. An Executed Service Agreement that contains the information required under this Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

12.5 Distribution Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Distribution Provider determines that its Distribution Facilities are not capable of providing Distribution Service without (1) degrading or impairing the reliability of service to Native Load or Distribution Customers , or (2) interfering with the Distribution Provider's ability to meet prior firm contractual commitments to others, the Distribution Provider will be obligated to expand or upgrade its Distribution System pursuant to the terms of Section 13.3. The Distribution Customer must compensate the Distribution Provider for any necessary transmission facility additions pursuant to the terms of Section 24. To the extent the Distribution Provider can relieve any system constraint more economically by redispatching the Distribution Provider's resources than through constructing upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Distribution Provider pursuant to the terms of this Tariff. Section 24. Any redispatch, Distribution System Upgrade or Direct Assignment Facilities costs to be charged to the Distribution Customer on an incremental basis under the

Tariff will be specified in the Service Agreement prior to initiating service.

12.6 Curtailment of Distribution Service: In the event that a Curtailment on the Distribution Provider's Transmission System or Distribution System, or a portion thereof, is required to maintain reliable operation of such systems, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Distribution Provider will curtail service to Distribution Customers on a basis comparable to the curtailment of service to the Distribution Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis. When the ISO or the Distribution Provider determines that an electrical emergency exists on the Transmission System or Distribution System and implements emergency procedures to curtail Distribution Service, the Distribution Customer shall make the required reductions upon request of the Distribution Provider. However, the Distribution Provider reserves the right to Curtail, in whole or in part, any Distribution Service provided under the Tariff when, in the Distribution Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Distribution System. The Distribution Provider will notify all affected Distribution Customers in a timely manner of any scheduled Curtailments.

12.7 Classification of Distribution Service:

(a) The Distribution Customer may purchase Distribution Service to make sales of capacity and energy from multiple generating units that are on the Distribution Provider's Distribution Facilities. For such a purchase of Distribution service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(b) The Distribution Provider shall provide deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which distribution capacity is provided to the Distribution Customer shall be set forth in the Service Agreement for Distribution Service with each Point of Receipt. Points of Receipt and corresponding service shall be as mutually agreed upon by the Parties for Distribution Service. Each Point of Delivery at which Distribution Service is provided to the Distribution Customer shall be set forth in the Service Agreement for Distribution Service associated with each Point of Delivery. Points of Delivery and corresponding service shall be as mutually agreed upon by the Parties.

12.8 Scheduling of Distribution Service: Schedules for the Distribution Customer's Transmission Service and Distribution Service shall be submitted to the ISO according to the requirements set forth in the ISO Tariff.

13 Service Availability

13.1 General Conditions: The Distribution Provider will provide Distribution Service over, on or across its Distribution System to any Distribution Customer that has met the requirements of Section 14.

13.2 Initiating Service in the Absence of an Executed Service Agreement: If the Distribution Provider and the Distribution Customer requesting Distribution Service cannot agree on all the terms and conditions of the Service Agreement, the Distribution Provider shall file with the Commission, within thirty (30) days after the date the Distribution Customer provides written notification directing the Distribution Provider to file, an unexecuted Service Agreement containing terms and conditions deemed appropriate by the Distribution Provider for such requested Distribution Service. The Distribution Provider shall commence providing Distribution Service subject to the Distribution Customer agreeing to (i) compensate the Distribution Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Tariff including posting appropriate security deposits in accordance with the terms of Section 15.3.

13.3 Obligation to Provide Distribution Service that Requires Expansion or Modification of Distribution Facilities: If the Distribution Provider determines that it cannot accommodate a Completed Application for Distribution Service because of insufficient capability on its Distribution Facilities, the Distribution Provider will use due diligence to expand or modify its Distribution Facilities to provide the requested Distribution

Service, provided the Distribution Customer agrees to compensate the Distribution Provider for such costs pursuant to the terms of Section 24. The Distribution Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those Distribution Facilities that the Distribution Provider has the right to expand or modify.

13.4 Deferral of Service: The Distribution Provider may defer providing service until it completes construction of new distribution facilities or upgrades needed to provide Distribution Service whenever the Distribution Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing services.

13.5 Other Distribution Service Schedules: Eligible Customers receiving Distribution service under other agreements on file with the Commission may continue to receive Distribution service under those agreements until such time as those agreements may be modified by the Commission.

13.6 Real Power Losses: Real Power Losses are associated with all Distribution service. The Distribution Provider is not obligated to provide Real Power Losses. The Distribution Customer is responsible for replacing losses associated with all Distribution Service as calculated by the Distribution Provider. The applicable Real Power Loss factors are calculated as shown in Attachment A to this Tariff.

14 Distribution Customer Responsibilities

14.1 Conditions Required of Distribution Customers: Distribution Service shall be provided by the Distribution Provider only if the following conditions are satisfied by the Distribution Customer:

a. The Distribution Customer has pending a Completed Application for service;

b. The Distribution Customer meets the creditworthiness criteria set forth in Section 7;

c. The Distribution Customer will have arrangements in place for any other distribution service necessary to effect the delivery from the generating source to the Distribution Provider prior to the time service under Part II of the Tariff commences;

d. The Distribution Customer agrees to pay for any facilities constructed and chargeable to such Distribution Customer under this Tariff, whether or not the Distribution Customer takes service for the full term of its service; and

e. The Distribution Customer has executed a Service Agreement or has agreed to receive service pursuant to Section 13.2.

14.2 Distribution Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Distribution Customer. The Distribution Customer shall provide, unless waived by the Distribution Provider, notification to the Distribution Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Distribution Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of

Receipt. However, the Distribution Provider will undertake reasonable efforts to assist the Distribution Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

15 Procedures for Arranging Distribution Service

15.1 Application: A request for Distribution Service for periods of one year or longer must contain a written Application to: [Manager of Distribution Management & Strategies, SDG&E, 8316 Century Park Court, San Diego, California 92123], at least sixty (60) days in advance of the calendar month in which service is to commence. The Distribution Provider will consider requests for such firm Distribution Service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 15.5.The Distribution Provider shall time-stamp each completed Application record for establishing the priority of the Application.

15.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Distribution Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Distribution Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be received at the Point(s) of Receipt and delivered to the Receiving Party at the Point(s) of Delivery;

(vii) The requested Service Commencement Date and the term of the requested Distribution Service; and

15.3 Deposit: A Completed Application for Distribution Service also shall include a deposit of either one month's charge for service or the full charge for service requests of less than one month. If the Application is rejected by the Distribution Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Distribution Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Distribution Provider if the Distribution Provider is unable to complete new Facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Distribution Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Distribution Provider to the extent such costs have not already been recovered by the Distribution Provider from the Eligible Customer. The Distribution Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 16. If a Service Agreement for Distribution Service is executed, The deposit, with interest, will be returned to the Distribution Customer upon expiration or termination of the Service Agreement for Distribution Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR ' 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Distribution Provider's account.

15.4 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Distribution Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Distribution Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Distribution Provider shall return the Application, along with any deposit, with interest.

15.5 Response to a Completed Application: Upon receipt of a new or revised Application that fully complies with the requirements of this Tariff, the Eligible Customer shall be assigned a priority consistent with the date of the new or revised Application. Following receipt of a Completed Application, the Distribution Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either if it will be able to provide service without performing a System Impact Study or if such a study is needed to evaluate the impact of the Application pursuant to Section 16.1. The notice shall also include an estimate of the cost of the study. Responses by the Distribution Provider must be made as soon as practicable to all Completed Applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

15.6 Execution of Service Agreement: Whenever the Distribution Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 13.2, within fifteen (15) days after it is tendered by the Distribution Provider, will be deemed a withdrawal and termination of the Completed Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

15.7 Extensions for Commencement of Service: The Distribution Customer can obtain up to five (5) one-year extensions for the commencement of service. The Distribution Customer may postpone service by paying a non-refundable annual fee equal to one-month's charge for Distribution Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Distribution Service, and such request can be satisfied only by releasing all or part of the Distribution Customer's Capacity, the original Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Distribution Customer agrees to pay distribution rate for its Distribution Service concurrent with the new Service Commencement Date. In the event the Distribution Customer elects to release the Capacity, the fees or portions thereof previously paid will be forfeited.

16 Additional Study Procedures For Distribution Service Requests

16.1 Notice of Need for System Impact Study: After receiving a request for service, the Distribution Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Distribution Provider's methodology for completing a System Impact Study is provided in Attachment B. If the Distribution Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Distribution Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Distribution Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Distribution Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 15.3, shall be returned with interest.

16.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Distribution Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Distribution Provider shall rely, to the extent reasonably practicable, on existing studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Distribution Facilities.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Distribution Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii)For System Impact Studies that the Distribution Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 18.

16.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Distribution Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Distribution System upgrades required to provide the requested service in accordance with Attachment B. In the event that the Distribution Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Distribution Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Distribution Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Distribution Facilities will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new Distribution Facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 13.3, or the Completed Application shall be deemed terminated and withdrawn.

16.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Distribution System are needed to supply the Eligible Customer's service request, the Distribution Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Distribution Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it, together with the payment for the estimated costs to do the study, to the

Distribution Provider within fifteen (15) days of receipt of the Facilities Study Agreement by the Eligible Customer. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit pursuant to Section 15.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Distribution Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Distribution Provider is unable to complete the Facilities Study in the allotted time period, the Distribution Provider shall notify the Distribution Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Distribution Customer, (ii) the Transmission Customer's appropriate share of the cost of any required upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Distribution Customer shall provide the Distribution Provider with a letter of credit or other reasonable form of security acceptable to the Distribution Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Distribution Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

16.5 Facilities Study Modifications: Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Distribution Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Distribution Customer pursuant to the provisions of Part II of the Tariff.

16.6 Due Diligence in Completing New Facilities: The Distribution Provider shall use due diligence to add necessary facilities or upgrade its Distribution System within a reasonable time. The Distribution Provider will not upgrade its existing or planned Distribution System in order to provide the requested Distribution Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

16.7 Partial Interim Service: If the Distribution Provider determines that it will not have adequate Distribution Facilities to satisfy the full amount of a Completed Application for Distribution Service, the Distribution Provider nonetheless shall be obligated to offer and provide the portion of the requested Distribution Service that can be accommodated without addition of any facilities and through redispatch. However, the Distribution Provider shall not be obligated to provide the incremental amount of requested Distribution Service that requires the addition of facilities or upgrades to the Distribution System until such facilities or upgrades have been placed in service.

17 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Distribution Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Distribution Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Distribution Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

18 Procedures if The Distribution Provider is Unable to Complete New Distribution Facilities for Distribution Service

18.1 Delays in Construction of New Facilities for Distribution Services: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Distribution Provider shall promptly notify the Distribution Customer. In such circumstances, the Distribution Provider shall within thirty (30) days of notifying the Distribution Customer of such delay, convene a technical meeting with the Distribution Customer to evaluate the alternatives available to the Distribution Customer. The Distribution Provider also shall make available to the Distribution Customer studies and work papers related to the delay, including all information that is in the possession of the Distribution Provider that is reasonably needed by the Distribution Customer to evaluate any alternatives.

18.2 Alternatives to the Original Facility Additions: When the review process of Section 18.1 determines that one or more alternatives exist to the originally planned construction project, the Distribution Provider shall present such alternatives for consideration by the Distribution Customer. If, upon review of any alternatives, the Distribution Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Distribution Provider to submit a revised Service Agreement for Distribution Service. the event the Distribution Provider concludes that no reasonable alternative exists and the Distribution Customer disagrees, the Distribution Customer may seek relief under the dispute resolution procedures pursuant to Section 10 or it may refer the dispute to the Commission for resolution.

18.3 Refund Obligation for Unfinished Facility Additions: If the Distribution Provider and the Distribution Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Distribution Service shall terminate and any deposit made by the Distribution Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Distribution Customer shall be responsible for all prudently incurred costs by the Distribution Provider through the time construction was suspended.

19 Provisions Relating to Distribution Construction and Services on the Systems of Other Utilities

19.1 Responsibility for Third-Party System Additions: The Distribution Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Distribution Provider will undertake reasonable efforts to assist the Distribution Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

19.2 Coordination of Third-Party System Additions: In circumstances where the need for Distribution Facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of distribution facilities on other systems, the Distribution Provider shall have the right to coordinate construction on its own system with the construction required by others. The Distribution Provider, after consultation with the Distribution Customer and representatives of such other systems, may defer construction of its new distribution transmission facilities, if the new distribution facilities on another system cannot be completed in a timely manner. The Distribution Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Distribution Provider of its intent to defer construction pursuant to this section, the Distribution Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 8 or it may refer the dispute to the Commission for resolution.

20 Changes in Service Specifications

Any request by a Distribution Customer to modify Receipt and Delivery shall be treated as a new request for service in accordance with Section 15 hereof, except that such Distribution Customer shall not be obligated to pay any additional deposit if the service does not exceed the amount in the existing Service Agreement. While such new request is pending, the Distribution Customer shall retain its priority for service at the existing Point(s) of

Receipt and Point(s) of Delivery specified in its Service Agreement.

21 Metering and Power Factor Correction at Receipt and Delivery Points(s)

21.1 Distribution Obligations: Unless otherwise agreed, the Distribution Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Distribution Provider. Such equipment shall remain the property of the Distribution Customer.

21.2 Distribution Provider Access to Metering Data: The Distribution Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

21.3 Power Factor: Unless otherwise agreed, the Distribution Customer is required to maintain a power factor within the same range as the Distribution Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

22 Compensation for Distribution Service

Rates for Distribution Service are provided in the Schedules appended to this Tariff Distribution Service (Schedule WDS1). The Distribution Provider shall use Part II of the Tariff to make its Third-Party Sales. The Distribution Provider shall account for such use at the applicable Tariff rates, pursuant to Section 6.

23 Stranded Cost Recovery

The Distribution Provider may seek to recover stranded costs from the Distribution Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888 and 888-A. However, the Distribution Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

24 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Distribution Provider in connection with the provision of Distribution Service identifies the need for new facilities, the Distribution Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Distribution Provider identifies capacity constraints that may be relieved more economically by redispatching the Distribution Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Distribution Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

SCHEDULE WDS 1

Wholesale Distribution Service

Subject to approval under Section 205 or Section 212 of the Federal Power Act the Distribution Customer shall compensate the Distribution Provider each month for Distribution Service at the sum of the applicable charges set forth below.

A. Distribution Service Charges:

a. Distribution Service for a Distribution Customer Who is an Electric Utility

The monthly charge for Distribution Service to a Distribution Customer who is an electric utility shall be based upon the following charges:

1. A customer service charge (See Section B.1): $_____/month;
2. A distribution demand charge (See Section B.2a): $_____/kW/month;
3a. Customer advance associated with Direct Assignment Facilities (See Section B.3a): $_____ lump sum payment;
3b. Monthly Facilities Charge associated with Direct Assignment Facilities (See Section B.3b): $_____/kW/month;
4. A cost of ownership charge for Direct Assignment Facilities (See Section B.4): $_____/month;
5. Power factor adjustment charge (See Section B.5): $_____/month;
6. Distribution loss adjustment charge (See Section B.6): $_____/month; and
7. Costs associated with avoiding an impairment, if any (See Section B.7): $_____ lump sum payment

b. Distribution Service for a Distribution Customer Who is a Generator

The monthly charge for distribution service to serve a generator shall consist of the following:

1. A customer service charge (See Section B.1) $_____/month;

2a. Customer advance associated with Direct Assignment Facilities (See Section B.3) $_____/month;

2b. Monthly Facilities Charge associated with Direct Assignment Facilities (See Section B.3b) $_____/kW/month;

3. A distribution demand charge associated with upgrades (See Section B.2b) $______/kw/month

4. Cost of ownership charge for Direct Assignment Facilities (See Section B.4):$_____/month;

5. Power factor adjustment charge (See Section B.5) $_____/month;

6. Loss adjustment charges (See Section B.6) $_____/month; and

7. Costs associated with avoiding an impairment, if any $_____/lump sum payment.

B. Description of Specific Charges

1. Customer Service Charge

A fixed monthly distribution customer service charge shall be assessed to reimburse the Distribution Provider for its costs of labor and supervision for billing services which it provides to the Distribution Customer for the specified Service Point of Delivery, including, among other things, billing, accounting for reactive power and distribution facilities usage as provided in this Tariff. An individual special study is required to determine this charge.

2a. Distribution Demand Charge Associated with an Electric Utility

Distribution Customers that are electric utilities shall pay a Distribution Demand Charge. The Distribution Demand Charge shall recover the higher of: (a) the Distribution Customer's proportionate share of the embedded costs (including expansion costs) of the Distribution Facilities that are used to serve the Distribution Customer's load (excluding Direct Assignment Facilities); or (b) the incremental cost of whatever expansions or upgrades to the Distribution Facilities are required to serve the Distribution Customer's load (excluding Direct Assignment Facilities).

The Distribution Provider shall undertake a System Impact Study to identify: (a) which preexisting Distribution Facilities will be used to serve the Distribution Customer's load; and (b) what upgrade or expansions to the preexisting Distribution Facilities, if any, will be required to serve the Distribution Customer's load. The Distribution Provider will then calculate a revenue requirement based upon the higher of embedded costs (as expanded) or incremental costs. The Distribution Demand Charge shall be assessed according to the Distribution Customer's metered quantities at the Point of Receipt.

If the revenue requirement is based upon embedded costs (as expanded), the cost of the Distribution Facilities used to serve the Distribution Customer shall be calculated according to the Distribution Customer's proportionate share of the total load served from the identified Distribution Facilities. The monthly demand charge shall be calculated by dividing the annual revenue requirement associated with the identified Distribution Facilities by the sum of the Distribution Customer's twelve monthly maximum peak demands imposed on those facilities.

2b. Distribution Demand Charge Associated with a Generator

Although a Distribution Customer who is a generator will not be charged for an allocated portion of preexisting Distribution Facilities, he will be responsible for the costs of distribution upgrades or an allocated portion of the upgrades that directly benefit him. The Distribuion customer will have one of two options to pay for these upgrades. First, he can pay a Customer Advance as calculated in Exhibt 7c or he can pay a monthly demand charge as derived in Exhibit 7b.

3a. Customer Advance Associated with Direct Assignment Facilities

In accordance with Attachment A of this Tariff, the Distribution Provider will calculate a customer advance for Direct Assignment Facilities that will be payable by the Distribution Customer at the time a Service Agreement is signed (See Attachment A). If the customer terminates service, the customer agrees to pay for the remaining cost of such facilities whether or not it takes service for the full term specified in the Service Agreement.

The remaining life of the facilities will be the depreciated installed cost of the Added Facilities plus removal costs, less salvage. In addition, the Distribution Customers shall pay an amount equal to the difference between (i) the sum of the payments which would have been made for the Added Facilities during the period in which this Agreement was in effect, if the rate had been calculated pursuant to a traditional depreciated rate base methodology, and (ii) the sum of the payments actually made, or which had become due, under this Agreement as of the date of termination. Such comparison shall be made for all payments made or due upon termination of this Agreement in accordance with this provision. The Distribution Provider shall file all charges under this provision with the FERC prior to termination. Following termination, the Distribution Provider shall remove the Added Facilities from service to the Distribution Customer.

3b. Monthly Facilities Charge Associated with Direct Assignment Facilities
Under the WDT, the Distribution Customer will be given one of two options to pay for Direct Assignment Facilities. First, the customer can elect to pay a customer advance which will recover the total cost of these facilities at the time he signs the Service Agreement. Second, the Distribution Customer can elect to pay a Monthly Facilities Charge that will recover the annual cost of these facilities. In the latter case, the customer will have to agree to pay for the remaining cost of such facilities whether or not it takes service for the full term specified in the Service Agreement. The remaining life of the facilities will be determined in accordance with Section B.3a of Schedule WDS-1.

4. Cost of Ownership Charge For Direct Assignment Facilities
The Cost of Ownership charge for Direct Assignment Facilities will recover the Distribution Provider's on going costs of owning and operating the Direct Assignment Facilities. As indicated in Attachment A, such on-going costs will include operation and maintenance costs, replacement costs (due to normal deterioration), and property taxes.

The Cost of Ownership Charge shall also include the on going costs of any facilities installed by the Distribution Customer or others, if any, that are deeded to the Distribution Provider. The manner is which the monthly cost of ownership charge is derived is shown in Attachment A.

5. Power Factor Adjustment Charge
Unless otherwise agreed, the Distribution Customer is required to maintain a power factor within the rage of 0.95 leading to 0.95 lagging during daily peak

hours from 10 AM to 6 PM. If consumption falls outside this range a power factor adjustment charge as indicated in Attachment A, shall be charged.

6. Distribution Loss Adjustment Charge

a. Distribution Loss Adjustment Charge Applicable to A Distribution Customer Who is an Electric Utility

A Distribution Customer who is an electric utility will cause the Distribution Provider to incur energy losses on the Distribution Facilities used to provide service. To insure the Distribution Provider is compensated for these losses, the Distribution Customer will be required to pay for these losses.

The losses will be paid by the Distribution customer on a monthly basis and will be calculated using standard engineering formulas applicable to the Distribution Customers use of the Distribution Providers distribution system. The energy loss factor calculated by these formulas shall be applied to a Customer's monthly energy consumption for the billing month. The energy loss charge shall will be priced in accordance with Attachment A.

b. Distribution Loss Adjustment Factors Applicable to a Distribution Customer Who is a Generator

The generator in the process of inserting power into the Distribution Provider's distribution system could increase or reduce the energy losses of the Distribution Facilities. In this circumstance, the generator will be charged or compensated, as the case may be, for these losses. A loss charge or compensation shall be made in accordance with Attachment A.

7. Definition:

For purposes of WDS-1, following terms and conditions shall have the following meaning:

a. "Impairment": Any event that could result from Distribution Service which is reasonable likely to cause (i) the inclusion in gross income for federal income tax purposes of the interest paid and/or to be paid on any local-furnishing private activity bonds ("Bonds") as described in Section 142(f) of the Internal Revenue

Code of 1986, as amended, or in any predecessor statute (the "Code"), issued for the benefit of Distribution Provider, (ii) the inclusion in gross income of interest for federal income tax purposes on debt which is reasonably expected to be issued in the future to finance distribution or generation facilities of Distribution Provider, or to be issued to refinance any outstanding Bonds issued for the benefit of Distribution Provider, or (iii) the loss of the deductibility, under Section 150 of the Code, of any interest expense associated with interest paid or to be paid on any such Bonds.

c. "Costs associated with avoiding an Impairment": All costs reasonably necessary to avoid or minimize the costs of an Impairment including: (i) redispatch of generation; (ii) construction or other physical modification of Distribution Provider's System; and/or (iii) redemption, defeasance or financing of Bonds (the "Refinancing"). Among other things, the costs of Refinancing shall include (A) the costs, including, but not limited to, increased interest cost of refinancing any outstanding Bonds which must be redeemed or defeased, (B) the increased interest costs associated with the inclusion in gross income for Federal income tax purposes of interest on any debt to be issued to finance the distribution and generation facilities of Transmission Provider and (C) any increased income and franchise tax liability of Distribution Provider resulting from the loss of deductibility of interest expense associated with interest on any Bonds issued or to be issued for the benefit of Distribution Provider. For purposes of computing costs resulting from increased interest costs associated with (B), it shall be assumed that Distribution Provider will have access to State of California private activity bond volume cap under Section 146 of the Code to finance distribution system costs to the same proportionate extent as Distribution Provider's post-1985 distribution system costs in fact have been financed with tax-exempt Bonds.

ATTACHMENT A

Form Of Service Agreement For

Wholesale Distribution Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between ______________ (the Distribution Provider), and ____________ ("Distribution Customer").

2.0 The Distribution Customer has been determined by the Distribution Provider to have a Completed Application for Firm Point-To-Point Distribution Service under the Wholesale Distribution Tariff.

3.0 The Distribution Customer has provided to the Distribution Provider an Application deposit in accordance with the provisions of Section 15.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Distribution Provider agrees to provide and the Distribution Customer agrees to take and pay for Firm Point-To-Point Distribution Service in accordance with the provisions of Part II of the Tariff and this Service Agreement and Schedules attached here to.

6.0 The Distribution Customer shall make a customer advance payment to the Distribution provider for all Direct Assignment Facilities at the time it returns an executed Service Agreement.

7.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Distribution Provider:

____

____

____

Distribution Customer:

____

____

____

8.0 Interconnection

8.1 Interconnection of Distribution Customer's Wholesale Distribution Load:

8.1.1 Direct Assignment Facilities for the interconnection of the Distribution Customer's Wholesale Distribution Load to the Distribution Provider's Distribution Facilities shall be installed, operated and maintained in accordance with Good Utility Practice.

8.1.2 The Distribution Customer shall specify: (i) the voltage level of service desired, provided such voltage shall be compatible with standard voltages used on the Distribution Provider's system, and (ii) any applicable service criteria of the Distribution Customer, including, but not limited to, any redundancy desired in elements available to service Wholesale Distribution Load from Distribution Provider's Distribution Facilities. If technically feasible, the Distribution Provider shall provide service at such voltage and in accordance with such criteria, conditioned on the Distribution Provider obtaining any necessary regulatory permits and complying with any other federal, state, or local requirements for the construction of any such facilities.

8.1.3 The Distribution Customer shall keep the Distribution Provider informed on a timely basis of changes in Wholesale Distribution Load and cooperate in planning any addition to or upgrade of Direct Assignment Facilities to accommodate load growth or additions. The Distribution Customer shall provide to the Distribution Provider by September 1 of each year an update of its total load by delivery point and its amount of interruptible load (location, conditions, and limitations) for the following five calendar years.

8.1.4 The Distribution Provider shall own, operate, and maintain all Direct Assignment Facilities on the Distribution Provider's side of the Point of Delivery. The Distribution Customer shall pay all costs and expenses for such Direct Assignment Facilities that are used exclusively to provide Distribution Service to the Distribution Customer including, but not limited to, the costs of permitting, planning, procuring, constructing, owning, maintaining, and operating any such facilities.

8.1.5 The Distribution Customer shall provide and maintain, at its sole expense, facilities on its side of the Point of Delivery in accordance with Good Utility Practice. The Distribution Customer shall install protective equipment on its system and take any other reasonable measures to protect the safe and reliable operation of the Distribution Provider's system from disturbances on the Distribution Customer's system in accordance with Good Utility Practice.

8.1.6 If the Distribution Customer does not maintain its power factor pursuant to the provisions of the Tariff, then the Distribution Provider will charge the Distribution Customers a Power Factor Adjustment Charge pursuant to the provisions of this Tariff.

8.1.7 The Distribution Customer shall provide the Distribution Provider access to the Distribution Customer's interconnection facilities to the extent necessary for the Distribution Provider to construct, operate, or maintain interconnection facilities. The Distribution Customer agrees to grant the Distribution Provider all necessary easements and rights of way, including adequate and continuing access rights, on the property of the Distribution Customer to transport, install, operate, maintain, replace, and remove the interconnection facilities, and any equipment or line extension that may be provided, owned, operated and maintained by the Distribution Provider on the property of the Distribution Customer. The Distribution Customer agrees to grant such easements and rights of way to the Distribution Provider at no cost and in a form satisfactory to the Distribution Provider and capable of being recorded in the office of the County recorder.

8.1.8 The Parties shall cooperate with one another in scheduling maintenance to any interconnection Facility or in taking any interconnection facility out of service, provided that in an emergency the Distribution Provider may take facilities out of service if necessary to protect the Distribution Provider's system.

8.2 Interconnection of Distribution Customer's Generation

8.2.1 The Distribution Customer shall interconnect its Generation with the Distribution Provider's Distribution Facilities in accordance with all applicable ISO, WSCC and NERC criteria, and Good Utility Practice.

8.2.2 The Distribution Customer, at its sole expense, shall design, own, procure, install, operate and maintain all equipment and facilities, including the Generation, on its side of the Point of Receipt (Distribution Customer's Facilities). The Distribution Provider shall design, own, install, and maintain all facilities necessary to interconnect the Distribution Customer's Generation on the Distribution Provider's side of the Point of Receipt (Distribution Direct Assignment Facilities) at the Distribution Customer's sole expense to the Extent permitted by Commission policies. Such facilities shall include any equipment necessary to protect the Distribution Provider's electric system, employees, and customers from damage or injury arising out of or connected with the operation of the Distribution Customer's Facilities, including, but not limited to, short circuit protection, breaker closing/reclosing control, unit tripping, loss of synchronism, over current/under current devices such as relays, remote terminal units, circuit breakers, and meters. The Distribution Customer's Facilities, and their operation and maintenance, shall meet the Distribution Provider's specifications and shall be subject to inspection and testing by the Distribution Provider. follows:

8.2.2.1 Design of Interconnection Facilities

The Distribution Customer, at Distribution Customer's sole expense, shall acquire all permits and approvals and complete all environmental impact studies necessary for the design, construction, installation, operation, and maintenance of the Interconnection Facilities.

The Distribution Customer shall provide to the Distribution Provider Distribution Customer's electrical specifications and design drawings pertaining to the Interconnection Facilities for Distribution Provider's review prior to finalizing design of the Interconnection Facilities and before beginning construction work based on such specifications and drawings. Distribution Customer shall provide to the Distribution Provider reasonable advance written notice of any changes in the Interconnection Facilities and provide to the Distribution Provider specifications and design drawings of any such changes for the Distribution Provider's review and approval. The Distribution Provider may require modifications to such specifications and designs as it deems necessary to allow the Distribution Provider to operate the Distribution Provider's electrical system in accordance with Good Utility Practices.

8.2.2.2 Interconnection Specifications for All Generators

A means of disconnection must be available on both sides of the Distribution Provider's metering and must be under the control of the Distribution Provider. Disconnection can be accomplished with switches, load break elbows, cutouts or secondary breakers. Generator disconnects can also be used provided that the switches meet with the Distribution Provider's approval and the Distribution Provider has preemptive control. Generator's with three-phase generators should be aware that certain conditions in the Distribution Provider's system may cause negative sequence currents to flow in the generator. It is the sole responsibility of the Generator to protect its equipment from excessive negative sequence currents. The Generator will be required to provide suitable devices to ensure adequate protection for:

a) all faults on the Generator's system
b) all faults on the Distribution Provider's system
c) back feed or start-up of a generator into a dead utility bus

The following Generator protective devices are required as a minimum to effect connection and separation of the Distribution Provider and Generator (For induction generators below 10 kW, the following are recommended but not required.):

a) individual phase over current trip devices,
b) under voltage trip devices,
c) over/under frequency trip devices,
d) synchronizing or equivalent controls, either automatic or manual, supervised by a synchronizing relay if over 1 MW, to ensure a smooth connection with the Distribution Provider's system.

For synchronous generators, sufficient generator reactive capability shall be provided to withstand normal voltage changes on the Distribution Provider's electric system. For induction generators, capacitor installations will likely be required for reactive power support. Such capacitors will be at the expense of the Distribution Customer. For induction generators less than 100 kW, some of the trip devices may be waived by the Distribution Provider.

8.2.2.3 Additional Interconnection Design Specifications
Generators interconnected above 50 kV must be equipped with Power System Stabilizers. The Distribution configuration must meet the Distribution Provider's and the WSCC regional reliability criteria.
Where interconnection is at or below 480 V, the Generator shall be served by a dedicated transformer except in the following circumstances: a) the generator is under 10 kW, or b) the generator is an under 100 kW induction generator that explicitly provides for 24-hour immediate access by the Distribution Provider to all interconnection facilities.

For Generator capacity above 100 kW, Generator shall also (a) install relaying to provide adequate protection for unbalanced or single phase conditions on the Distribution Provider's system or deteriorating voltage waveform conditions on the generator and (b) install sensitive current unbalance relays

For Generator capacity greater than 1 MW, Generator shall also provide sensitive ground protection.

For Generator capacity greater than 2 MW, Generator shall also provide telemetering of generator output to the Distribution Provider.

For Generator capacity of 5 MW or greater, the Distribution Customer shall provide a: a) a complete supervisory control system, including indication of the Generator's main breaker, allowing operation of Generator from the Distribution Provider's control center, or

9.0 Interconnection Facilities and Review Disclaimer

Distribution Providers review of the design, construction, operation, or maintenance of Interconnection Facilities or Generation facility shall not constitute any representation as to the economic or technical feasibility, operational capability, or reliability of such Facilities. Distribution Customer shall in no way represent to any third party that any such review by Distribution Provider of such Facilities is a representation by Distribution Provider as to the economic or technical feasibility, operational capability, or reliability of such Facilities. Distribution Customer is solely responsible for economic and technical feasibility, operational capability, and reliability of the Interconnection Facilities and the Generation facility.

Distribution Provider shall notify Distribution Customer in writing of the outcome of Distribution Provider's review of the design and all of the specifications, drawings, and explanatory material for Distribution Customer's Interconnection Facilities (and the Generation facility, if requested by Distribution Provider) within thirty (30) calendar days of the receipt of the design and all of the specifications, drawings, and explanatory material for the Interconnection Facilities (and the Generation facility, if requested by Distribution Provider). Any flaws in the design perceived by Distribution Provider in the review of all of the specifications, drawings, and explanatory material for the Interconnection Facilities (and the Generation facility, if requested by Distribution Provider) shall be described in Distribution Provider's written notification.

10.0 Operational Aspects of Generation Interconnection

The Distribution Customer shall not commence parallel operation of the generating facility until written approval for operation of the Interconnection Facilities has been given by Distribution Provider. Such approval shall not be unreasonably withheld. Distribution Customer shall notify Distribution Provider of Distribution Customer's intent to energize the Interconnection facilities not less than forty-five (45) calendar days prior to such energizing. Distribution Provider shall have the right to inspect the Interconnection Facilities within thirty (30) calendar days of receipt of such notice. If the Interconnection Facilities are not approved by Distribution Provider, Distribution Provider shall provide written notice to Distribution Customer stating the reasons for Distribution Provider's disapproval within five (5) calendar days of the inspection.

The Distribution Customer shall provide written notice to Distribution Provider at least fourteen 14) calendar days prior to the initial and subsequent testing of the Protective Apparatus. The Protective Apparatus shall be tested thereafter at intervals not to exceed three (3) years using qualified personnel. Distribution Provider shall have the right to have a representative present at the initial and subsequent testing of the Protective Apparatus and to receive copies of the test results.

Distribution Customer shall operate and maintain the Interconnection Facilities in accordance with Good Utility Practices.

10.1 Nominal Voltage and Grounding

Distribution Provider's most common voltages are as follows:

a) Distribution system voltages are 4 and 12 kV

The majority of the common distribution voltages are grounded. Distribution Provider will provide information on the specific circuit serving the Generator.

10.2 Operating Requirements for Generators

In order for Distribution Provider to supply and maintain proper voltages to its Native Load Customers, Distribution Provider electric system voltages may fluctuate from the nominal values. Distribution Provider uses various regulation techniques to raise and lower both distribution and transmission system voltages in order to maintain desired customer service voltage. Generators shall design and operate its facilities to withstand such voltage changes and to respond with proper power factor adjustment in sufficient time so as not to interfere with Distribution Provider's voltage regulation.
Generators must assure that transformers serving both Native Load Customers and the Generator shall be identified with a special tag attached to the transformer or pole for the purpose of notifying Distribution Provider field crews of the possibility of back feed.

Distribution Provider may ground de-energized lines and equipment upon which work will be performed. Distribution Provider may test its electrical lines that have automatically tripped (de-energized) due to a fault by reclosing the affected circuit at least one time.

The Generator shall not reconnect his generator after a protective device trip unless his system is energized from an Distribution Provider. Additionally, generator control circuit(s) must be designed to prevent accidental generator connection to a dead utility system. Design variations are acceptable provided the requirements of this Exhibit are satisfied.

Distribution Customers with Generators interconnected above 50 kV may be required to maintain a voltage schedule within specified voltage ranges.

10.3 Power Factor

Distribution Provider may require that the Distribution Customer to maintain specified corrected power factors at peak load. In this event, the Distribution Customer is responsible to maintain such peak load corrected power factors at the Point of Receipt, as specified by Distribution.

Unless otherwise agreed, the Distribution Customer is required to maintain a power factor within the rage of 0.95 leading to 0.95 lagging during daily peak hours from 10 AM to 6 PM. If consumption falls outside this range a power factor adjustment charge as indicated in this Agreement will be charged.

10.4 Power Factor Maintenance and Future Changes in Target Power Factor

Distribution Provider may change the target power factor from time to time upon notice to Distribution Customer. Distribution Provider shall allow reasonable lead time for corrective action by the Distribution Customer. If the Distribution Customer does not comply with the new corrected power factor requirements, Distribution Provider may take the necessary corrective steps as described in the Service Agreement.

In no event shall Distribution Customer be responsible for their reactive requirements (VARS) through the Transmission Owner Tariff or the ISO Tariff and, in addition, incur responsibility for local distribution power factor correction for the same VAR requirements. If local power factor correction is installed at Distribution Customer's expense, such correction shall be credited to the Distribution Customer's meter readings.

11. Real Property Rights

Distribution Customer agrees to grant Distribution Provider all necessary easements and rights of way, including adequate and continuing access rights, on property of Distribution Customer to transport, install, operate, maintain, replace, and remove the Direct Assignment Facilities, and any equipment or line extension that may be provided, owned, operated and maintained by Distribution Provider on the property of Distribution Customer. Distribution Customer agrees to grant such easements and rights of way to Distribution Provider at no cost and in a form satisfactory to Distribution Provider and capable of being recorded in the office of the County Recorder.

If any part of Distribution Provider's Direct Assignment Facilities, equipment, and/or line extension is to be installed on property owned by other than Distribution Customer, or under the jurisdiction or control of any other individual, agency or organization, Distribution Provider may, at its discretion and at Distribution Customer's cost and expense obtain from the owners thereof all necessary easements and rights of way including adequate and continuing access rights, and/or such other grants, consents and licenses, in a form satisfactory to Distribution Provider, for the construction, operation, maintenance, and replacement of Direct Assignment Facilities, equipment, and/or line extension upon such property.

If Distribution Provider does not elect to obtain or cannot obtain such easements and rights of way, Distribution Customer shall obtain them at its cost and expense. If Distribution Customer requests, Distribution Provider shall cooperate with and assist Distribution Customer in obtaining said easements and rights of way. In any event, Distribution Customer shall reimburse Distribution Provider for all costs incurred by Distribution Provider in obtaining, attempting to obtain or assisting in obtaining such easements and rights of way.

Distribution Provider shall have the right of ingress to and egress from the Generation facility at all reasonable hours for any purposes reasonably connected with the Service Agreement or the exercise of any and all rights secured to Distribution Provider by law or its tariff schedules on file with the Commission.

Distribution Provider shall have no obligation to Distribution Customer for any loss, liability, damage, claim, cost, charge, or expense due to Distribution Provider's inability to acquire a satisfactory right of way, easement or other real property interest necessary to Distribution Provider's performance of its obligations under the Service Agreement or this Tariff.

Nothing in this Service Agreement shall be construed to require Distribution Provider to acquire land rights through condemnation or any other means for Distribution Customer either inside or outside of Distribution Provider's service area unless Distribution Provider shall in its sole discretion elect to do so.

12. Assignment

Neither Party shall voluntarily assign its rights nor delegate its duties under the Service Agreement without the written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation made without such written consent shall be null and void. Consent for assignment shall not be withheld unreasonably.

13. Non-Waiver

None of the provisions of the Service Agreement shall be considered waived by either Party except when such waiver is given in writing. The failure of any Party at any time or times to enforce any right or obligation with respect to any matter arising in connection with the Service Agreement shall not constitute a waiver as to future enforcement of that right or obligation or any right or obligation of the Service Agreement.

14. Section Headings

Section headings appearing in the Service Agreement are inserted for convenience only and shall not be construed as interpretations of text.

15. Governing Law

The Service Agreement shall be interpreted, governed, and construed under the laws of the State of California as if executed and to be performed wholly within the State of California except to the extent disputes are the responsibility of the Commission.

16. Amendment, Modification or Waiver

Any amendments or modifications to this Agreement, other than to Attachment A, shall be in writing and agreed to by both Parties. The failure of any Party at any time or times to require performance of any provision hereof shall in no manner affect the right at a later time to enforce the same. No waiver by any Party of the breach of any term or covenant contained in this Agreement, whether by conduct or otherwise, shall be deemed to be construed as a further or continuing waiver of any such breach or a waiver of the breach of any other term or covenant unless such waiver is in writing.

17. The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Distribution Provider:

By: ______________________ ______________ ______________

Name Title Date

Distribution Customer:

By: ______________________ ______________ ______________

Name Title Date

Specifications For

Wholesale Distribution Service

1.0 Term of Transaction: ______________________________

Start Date: ______________________________________

Termination Date: ________________________________

2.0 Description of capacity and energy to be transmitted by Distribution Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ______________________________

Delivering Party: _________________________________

Delivery Voltage: _________________________________

4.0 Point(s) of Delivery: _____________________________

Receiving Party: __________________________________

Delivery Voltage: _________________________________

5.0 Maximum amount of capacity and energy to be transmitted:

____

6.0 Designation of party(ies) subject to reciprocal service obligation: ____

7.0 Name(s) of any Intervening Systems providing transmission service: ____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Customer Charge

8.2 Distribution Demand Charge: (See Attachment A, Exhibit 7)

8.3 Cost of Ownership Charge: (See Attachment A, Exhibit 4)

8.4a Customer Advance Associated with Direct Assignment Facilities: (See Attachment A, Exhibit 1a)

8.4b Monthly Facilities Charge Associated with Direct Assignment Facilities: (See Attachment A, Exhibit 1b)

8.5 Power Factor Adjustment Charge:(See Attachment A, Exhibit 5)

8.6 Distribution Loss Adjustment Charge: (See Attachment A, Exhibit 6)

8.7 System Impact Study Charge: (See Attachment B)

8.8 Facilities Study Charge: (See Attachment C)

8.9 Transformer Loss Compensation Factor

For a Distribution Customer who is a generator, if the generation meter is on the low voltage side of the generation transformer, a transformer loss compensation factor shall be applied to determine the capacity and energy delivered to the Point of Receipt.

Distribution Service Agreement

Attachment A

Exhibit 1a

Calculation of Distribution Customer's Advance Payment

Distribution Customer ______________________________

Project Name and Location ______________________________

The total Advance Payment for Direct Assignment Facilities required for the above project prior to the start of construction is as follows:

1. Direct Assignment Facilities Incurred by the Distribution Provider

The Distribution Customer agrees to pay the Distribution Provider's total estimated cost of the facilities to serve the Distribution Customer, less credits, if any.

(From Exhibit 2 - Direct Assignment Facilities) $__________

2. ITCC Tax

The Distribution Customer must pay the taxes on such contributions, in addition to any other applicable contributions, such as facilities installed by the Distribution Customer, and deeded to the Distribution Provider.

(From Exhibit 3 - ITCC Tax) $__________

3. Total

(Sum of Installation Charge and ITCC Tax) $__________

If future relocation is required, it is not included in these cost determinations. The Distribution Customer is responsible for the cost of relocating the subject facilities herein. The future relocation costs will be determined at the time of relocation and are subject to approval by FERC.

Distribution Service Agreement

Attachment A

Exhibit 1b

Calculation of Monthly Facilities Charge Associated with Direct Assignment Facilities

Under the WDT, the Distribution Customer will be given one of two options to pay for Direct Assignment Facilities. First, the customer can elect to pay a customer advance which will recover the total cost of these facilities at the time he signs the Service Agreement. Second, the Distribution Customer can elect to pay a Monthly Facilities Charge that will recover the annual cost of these facilities. In the latter case, the customer will have to agree to pay for the remaining cost of such facilities whether or not it takes service for the full term specified in the Service Agreement.

If the Customer Elects to pay a monthly facilities charge the calculation of the charge is as follows:

1. Total Initial Installation Charge (Exhibit 2 Line 7) $_______

2. Annual Fix Carrying Charge (Note A) _______%

3. Annual Facilities Charge (Line 1 & Line 2) $______

4. Monthly Facilities Charge (Line 3/12 Months) $_______/mo.

Note A: The annual fix carrying charge will be derived to recover the Distribution's Provider's cost of capital, depreciation, O&M expenses, property taxes, income taxes, etc. related with the Direct Assignment Facilities.

Distribution

Service Agreement

Attachment A

Exhibit 2 - Direct Assignment Facilities

The following is the Distribution Provider's site-specific estimate (Gross Financial Costs -- labor, material, indirect and overhead cost components) for the facilities required to provide Distribution Service to the above project. It excludes any work on the Distribution Provider's facilities which is done for the convenience of the Distribution Provider, such as work to accommodate future system expansion, or capacity increases.

Description of Direct Assignment Facilities to be installed:

____

____

1. Protection System Modifications $__________
(installation and reconfiguration of protective devices)

2. Power Factor Correction $__________
(____KVAR of (_) Fixed, (_) Switched Capacitors required to attain ____% Power Factor)

3. Voltage Correction Devices $__________
(Installation of regulators, boosters, and capacitors)

4. Primary Extension Estimated Costs $__________
(Poles, conductors, other equipment)

5. Revenue Meters $__________
(Initial cost to install and the field set up revenue meters, plus the administrative costs of setting up the revenue data retrieval)

6. Telecommunications Facilities $__________
(Initial payments to telephone company for the installation of phone lines etc., plus related telecommunications work by the Distribution Provider to establish telecom links. Does not include on-going monthly service charges.)

7. Total Initial Installation Charge $__________
(Sum of 1 through 7)

Distribution

Service Agreement

Attachment A

Exhibit 3 - ITCC Tax

1. One-time advance payment by Distribution Customer
(From Exhibit 2 - Direct Assignment Facilities) $______

2. Value of trenching and conduits subject to ITCC (Description of facilities) $______

____

____

3. Total taxable amount(Sum of Items 1 thru 2) $______

4. Tax Rate 34%

5. Tax Due Tax Rate (line 4) x Taxable Amount (line 3)= $______

Distribution

Service Agreement

Attachment A

Exhibit 4 - Cost of Ownership Charge

For Direct Assignment Facilities

The Cost of Ownership for Direct Assignment Facilities is the Distribution Provider's on-going cost liabilities of owning and operating facilities, including such costs as maintenance costs, replacement costs (due to age and normal life and deterioration), and property taxes

1. Cost of Direct Assignment Facilities Installed by the Distribution Provider (From line 7 of Exhibit 2 - Installation Charge)

$_______

2. Cost of Direct Assignment Facilities Installed by Distribution Customer or Others and Deeded to the Distribution Provider (Based on Distribution Customer's Gross Financial installed cost) $______

3. ITCC Tax (From line 5 of Exhibit 3 - ITCC Tax) $______

4. Total Cost Basis (Sum of line 1, line 2 and line 3) $_______

5. Applicable Cost of Ownership Rate (Note A) ___XX___%
(Rate to be determined at time of request)

6. Applicable Monthly Cost of Ownership
(line 4 x line 5)/12 $___/month

Note A: Cost of ownership rate to be determined by Distribution Provider to recover ongoing costs Service Agreement

Attachment A

Exhibit 5 - Power Factor Adjustment Charge

The power factor adjustment charge will be designed to recover the Distribution Provider's incremental cost to install capacitor banks located at Distribution Provider's distribution substation level. The power factor adjustment charge factor shall be calculated at the time a Distribution Customer takes service under this Service Agreement.

Service Agreement

Attachment A

Exhibit 6 - Distribution Losses

A. Distribution Losses Applicable to a Distribution Customer Who is an Electric Utility

Based upon a case by case analysis, the Distribution Customer shall compensate the Distribution Provider for the monthly energy losses that occur on its distribution system. The energy losses will be based upon the Distribution Customer's maximum monthly demand and average energy use as applied to standard engineering loss formulas. The energy losses thus calculated will be converted to a percentage of the customers total average annual energy consumption. This percentage amount will then be applied to the customers monthly meter amount to adjust for distribution loss recovery by the Distribution Provider.

Example

Assume a Distribution Customers average monthly energy consumption is 1,000 MWH at the meter. Assume, based upon engineering formulas the customers average distribution losses are 50 MWH. The customers distribution loss factor is calculated as 5%.

Based upon the above calculation, the Distribution provider on a monthly basis will multiply the Customer's monthly metered energy consumption by 5%. The resultant energy losses times that months average monthly Power Exchange price will be paid by the customer to the Distribution Provider. In this example, the customer will pay Distribution Provider $1,250 (50 MWHs * 25 mills). This assumes an average Power Exchange cost of 25 mills for the applicable month.

B. Distribution Losses Applicable to a Distribution Customer Who is a Generator

Distribution losses applicable to the Services Agreement will reflect a Distribution Loss Factor (DLF) of 1.0. The use of a DLF of 1.00 implies that there are no energy loss payments or credits associated with the generation of energy under this service Agreement.

Service Agreement.

Attachment A

Exhibit 7a - Calculation of Distribution Demand Charge for A Distribution Customer Who is An Electric Utility

1.	Allocated Preexisting Distribution Facilities (Note A)	$_______
2.	Annual Fix Carrying Cost (Note B)	_______%
3.	Annual Revenue Requirements (Line 1 x Line 2)	$_______
4.	Monthly Demand Charge (Line 3 / Note C)	$_______/kw

Note A: The Distribution Provider shall do a special study to determine the allocated portion of preexisting facilities that should be assigned to the customer.

Note B: Note A: The annual fix carrying charge will be derived to recover the Distribution's Provider's cost of capital, depreciation, O&M expenses, property taxes, income taxes, etc. related with the allocated preexisting Distribution Facilities.

Note C: The sum of the Customers twelve monthly maximum demands as measured at the Customer's meter.

Service Agreement

Attachment A

Exhibit 7b - Calculation of Distribution Demand Charge for A Distribution Customer Who is A Generator

Although a Distribution Customer who is a generator will not be charged for an allocated portion of pre-existing Distribution Facilities, he will be responsible for the costs of distribution upgrades or an allocated portion of the upgrades that directly benefit him. The Distribution customer will have one of two options to pay for these upgrades. First, he can pay a Customer Advance as calculated in Exhibit 7c or he can pay a monthly demand charge as derived in this Exhibit.

1.	Distribution Upgrade or allocated portion thereof (Note A)	$_______
2.	Annual Fix Carrying Cost (Note B)	_______%
3.	Annual Revenue Requirements (Line 1 x Line 2)	$_______
4.	Monthly Demand Charge (Line 3 / Note C)	$_______/kw

Note A: The Distribution Provider shall determine the upgrade or allocated portion of the upgrade the Customer will pay. These upgrades will be determined in the Facility Study.

Note B: The annual fix carrying charge will be derived to recover the Distribution's Provider's cost of capital, depreciation, O&M expenses, property taxes, income taxes, etc. related with the upgrade.

Note C: The sum of the Customers twelve monthly maximum demands as measured at the Customer's meter.

Distribution Service Agreement

Attachment A

Exhibit 7c

Calculation of Distribution Customer's Advance Payment for a Distribution Customer Who is a Generator

Distribution Customer ____

Project Name and Location ____________________________________

The total Advance Payment for the upgrade facilities or an allocated portion thereof required for the above project prior to the start of construction is as follows:

1. Upgrade Costs or portion thereof incurred by the Distribution Provider
The Distribution Customer agrees to pay the Distribution Provider's total estimated cost of the facilities to serve the Distribution Customer, less credits, if any.

$___________

2. ITCC Tax
The Distribution Customer must pay the taxes on such upgrades. Calculation will be made similar to that shown in Exhibit 3 - ITCC Tax)

$___________

3. Total
(Sum of Installation Charge and ITCC Tax) $___________

ATTACHMENT B

Methodology for Completing a System Impact Study

The Distribution Provider will assess the capability of its Distribution System to provide the energy and capacity levels of the service requested. In determining the level of capacity available for new service requests, the Distribution Provider may exclude, from capacity to be made available for new service requests, that capacity needed to meet current and reasonably forecasted load of Native Load Customers Service, previously pending Applications for Distribution Service and existing contractual obligations under other rate schedules.

The System Impact Study shall include:

- An assessment whether the Distribution Provider's existing Distribution System is adequate to provide the requested service.
- A preliminary non-binding estimate of scope of the Direct Assigns Facilities and Distribution System upgrades required to provide the requested service.

ATTACHMENT C

Methodology for Completing a Facility Study

The Distribution Provider will utilize the results of the completed System Impact Study to:

- Determine the scope of the Direct Assigned Facilities and Distribution System upgrades required to provide the requested service. (Note that the scope of required new upgraded facilities should generally be the same as those determined in the System Impact Study. However, additional or changing information about the requested service, or changes to the Distribution Provider's system may warrant an addition assessment of the Distribution System impacts. Every reasonable effort should be made to utilize the results of the System Impact Study to avoid duplication of work.
- Determine the cost and schedule to construct the Direct Assigned Facilities and perform Distribution System upgrades necessary to provide the requested service.